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Pollution Control Guidance for Geothermal Energy Development

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Pollution Control Guidance for Geothermal Energy Development

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June 1978

POLLUTION CONTROL GUIDANCE
FOR
GEOTHERMAL ENERGY DEVELOPMENT

by

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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related polluttional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

This report provides preliminary pollution control guidance to be used by developers and regulators of geothermal energy. The report and similar ensuing reports are intended to develop the technical basis for eventual regulations.

Further information on the subjects of this report can be obtained from the Power Technology and Conservation Branch, Industrial Environmental Research Laboratory, Cincinnati, Ohio 45268.

David G. Stephan
Director
Industrial Environmental Research Laboratory
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PREFACE

This document originated as a result of the Environmental Protection Agency (EPA) concern as a member of the Interagency Geothermal Coordinating Council, that the development of geothermal energy as an alternative energy source not be constrained by uncertainties about environmental standards. It is the intent of EPA to ensure that technology-specific environmental goals are developed and maintained during the course of geothermal technology development in order that undue development delays be avoided and that a mature geothermal industry, compatible with national environmental goals, can be established.

The EPA envisions this document as the first of a series leading toward the establishment of regulatory standards for the geothermal industry. The series is expected to serve several purposes. First and foremost, it will serve to communicate EPA regulatory policies to geothermal developers on a comprehensive basis. Second, the series will update the state of knowledge with respect to known geothermal pollutants and their potential effects. Third, the series will describe state-of-the-art control technologies as they evolve and will describe the remaining needs where technologies are not sufficient. Finally, it will suggest ranges of discharge and emission limits within which the geothermal industry should strive to operate. Ideally, as more information becomes available, each document in the series will offer more definitive limits and more demonstrated confidence in available control technologies. The series would culminate in a document providing the basis for legally defensible regulations.

This document, as the first of the series, presents general information relevant to geothermal pollution problems and their control as they are viewed today. It should be kept in mind that the present data base is meager and that attempts to precisely define problems and their control would be incomplete. The purpose here is to present a first approximation to EPA's regulatory expectations and thereby to generate, through their publication, the necessary concern, proper perspective, and a logical and predictable approach to geothermal pollution control.

This document was prepared by the EPA, with guidance, input and review from its Geothermal Working Group, chaired by Dr. Gregory J. D'Alessio, Office of Energy, Minerals and Industry. The following EPA offices were represented:

- Office of Energy, Minerals and Industry
- Office of Water Supply
- Office of Planning and Management

- Office of Water Planning and Standards
- Office of Air Quality Planning and Standards
- Office of Radiation Programs
- Office of Noise Control Programs
- Office of Solid Waste Programs

The principal author of this document was Robert P. Hartley, Office of Energy, Minerals and Industry, Industrial Environmental Research Laboratory-Cincinnati. Several offices of the Department of Interior, Department of Energy, and other agencies have reviewed the document, and revisions, where appropriate have been incorporated.

Readers are urged to make known to the Environmental Protection Agency their views as to the content of this document. Comments should be addressed to:

U. S. Environmental Protection Agency
Office of Energy, Minerals and Industry
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Washington, D.C. 20460

ABSTRACT

This report summarizes the EPA regulatory approach toward geothermal energy development. The state of knowledge is described with respect to the constituents of geothermal effluents and emissions, including water, air, solid wastes, and noise. Pollutant effects are discussed. Pollution control technologies that may be applicable are described along with preliminary cost estimates for their application. Finally discharge and emission limitations are suggested that may serve as interim guidance for pollution control during early geothermal development.

CONTENTS

	<u>Page</u>
FOREWORD	111
PREFACE	1v
ABSTRACT	vi
FIGURES	x
TABLES	x11
 I. SUMMARY AND CONCLUSIONS	 1
Perspective	1
EPA Regulatory Approach	2
Precommercialization Regulations	2
Surface Water Protection	2
Ground Water Protection	2
Air Quality Protection	3
Noise Protection	3
Radiation Protection	3
Geothermal Pollutants and Sources	3
Environmental Concerns from Known Pollutants	5
Water Pollutants	5
Air Pollutants	5
Noise	6
Land-Disposed Wastes	6
Radiation	7
Pollution Control Technology	7
Air Pollution Control	7
Water Pollution Control	8
Land-Disposed Waste Control	10
Noise Control	10
 II. RECOMMENDATIONS	 11
Suggested Pollutant Limitations	11
Air Emissions	11
Water Discharges	11
Land-Disposed Wastes	12
Noise	12
Monitoring	12
Control Technology and Regulatory Development Needs	12
 III. INTRODUCTION	 13
Objectives	13
Background	13
Standards Problem	13
Perspective	13

	<u>Page</u>
EPA Geothermal Pollution Control Regulatory Approach . .	15
Air Pollution	16
Water Pollution	16
Land-Disposed Wastes	17
Noise	17
Radiation	18
IV. GEOTHERMAL POLLUTANTS AND PROCESS SOURCES	19
Wellfield Exploration, Development and Construction	
Activities	19
Fluid Distribution and Energy Conversion System	
Operations	20
Pollutants Derived from Geothermal Fluid	23
Noise Derived from Geothermal Operations	27
V. ENVIRONMENTAL EFFECTS OF KNOWN POLLUTANTS	30
General	30
Water Pollutants	30
Human Use	32
Aquatic Life	32
Agricultural Use	35
Industrial Water Supply	35
Air Pollutants	37
Effects on Humans	37
Effects on Plants and Crops	39
Noise Pollution	40
Land-Disposed Wastes	40
Radiation	40
VI. POLLUTION CONTROL TECHNOLOGY	41
Air Pollution	41
Stretford Process	41
Iron Catalyst Process	44
EIC Process	48
Dow Oxygenation Process	53
Other H ₂ S Removal Processes	58
Water Pollution	63
Wastewater Treatment Technologies	63
Wastewater Disposal Technologies	83
Solid Waste Disposal	103
Noise Control	104
VII. SUGGESTED POLLUTANT DISCHARGE LIMITS	106
General	106
Air Pollutant Limitations	106
Hydrogen Sulfide	106
Other Noncondensable Gases	107
Water Pollutant Limitations	107
Electric Power Generation	108

	<u>Page</u>
Non-Electric Uses	109
Sanitary Wastes and Construction Wastes	109
Land-Disposed Waste Limitations	110
Noise Limitations	110
VIII. FUTURE DEVELOPMENT OF EFFLUENT AND EMISSION STANDARDS . . .	111
IX. EFFLUENT AND EMISSION MONITORING	114
Air and Water Point Source Monitoring	114
Ambient Air Monitoring	115
Ambient Water Monitoring	116
Ground Water Monitoring	117
Land-Disposed Wastes	118
Noise Monitoring	118
Baseline Air and Water Monitoring	119
REFERENCES CITED	120
APPENDIX - Summary of Laws Requiring or Related to Geothermal Pollution Control	126

FIGURES

<u>Number</u>		<u>Page</u>
1	Simplified diagram of open cycle geothermal electric power generation system	21
2	Simplified diagram of closed loop geothermal electric power generation system	22
3	Simplified diagram of non-electric use of geothermal energy	22
4	Ranges of chemical constituent concentrations in geothermal fluids	24
5	Noncondensable gases in geothermal fluids	25
6	Cumulative frequency distribution from radon-222 in geothermal waters	26
7	Flow diagram of a Stretford Process	42
8	Stretford annual cost (mill/kwh) vs. power generation	44
9	Iron catalyst hydrogen sulfide removal process	45
10	Iron catalyst annual cost (mill/kwh) vs. power generation	47
11	EIC H ₂ S removal process with regeneration by roasting	48
12	EIC H ₂ S removal process with regeneration by leaching	49
13	EIC annual cost (mill/kwh) vs. power generation	53
14	Dow oxygenation H ₂ S removal process with in-line mixers	54
15	Dow oxygenation H ₂ S removal process with cocurrent packed tower	54
16	Dow oxygenation in-line system annual cost (mill/kwh) vs. power generation	57
17	Dow oxygenation packed system annual cost (mill/kwh) vs. power generation	58
18	Solid sorption H ₂ S removal process	59
19	Claus sulfur recovery process	60
20	Cut-away view of a granular mixed media filter	65
21	Cost estimates for sedimentation	67
22	Cost estimates for chemical precipitation with single stage lime addition	68
23	Cost estimates for chemical treatment for 2-stage lime addition	68
24	Cost estimates for chemical precipitation with alum addition	69
25	Cost estimates for chemical precipitation with ferric chloride addition	69
26	Cost estimates for filtration	70
27	Schematic presentation of reverse osmosis	71
28	Cost estimate for reverse osmosis system	72
29	Electrodialysis cell	72

<u>Number</u>		<u>Page</u>
30	Cost estimates for electrodialysis system	73
31	Mixed-bed ion exchange process	75
32	Cost estimates for ion exchange system	75
33	Principle of multiple stage flash evaporation	76
34	Multiple effect evaporation	77
35	Principle of compression still	77
36	Total costs for evaporation	78
37	Application of treatment technologies for achieving three effluent quality levels from high level waste	84
38	Application of treatment technologies for achieving three effluent quality levels from mid level waste	85
39	Application of treatment technologies for achieving three effluent levels from low level waste	86
40	Typical injection well set-up	88
41	Hole size cost comparison for wells (capital cost only) .	93
42	Annualized capital cost for injection of geothermal wastewaters	96
43	Total annual cost of evaporation ponds versus pond surface area	100
44	Annualized investment cost of spill containment ponds (10-foot depth)	103
45	Typical multi-chamber silencer	105
46	Twin-cylinder centrifugal expansion muffler for large volume fluid wasting	105

TABLES

<u>Number</u>		<u>Page</u>
1	Sound Levels from Various Sources at the Geysers	28
2	Pollutants Limited by Water Quality Standards in States with Geothermal Potential	31
3	Effects on Humans of Oral Ingestion of Compounds	33
4	Aquatic Life Criteria for Constituents in Geothermal Fluid	34
5	Agricultural Use Criteria for Constituents in Geothermal Fluids	36
6	Total Dissolved Solids Concentrations in Surface Waters That Have Been Used as Sources for Industrial Water Supplies	37
7	Effects on Humans of Inhalation of Gases or Vapors	38
8	Hydrogen Sulfide Effects on Humans.	39
9	Efficiencies of Control Technologies for Treatment of Specific Constituents in Wastewaters	80
10	Assumed Geothermal Waste Brine and Surface Water Discharge Concentrations	81
11	Geothermal Waste Brine Flow Rates and Concentration Levels for Various Uses	81
12	Removal Efficiencies Required for Treating Various Levels of Raw Geothermal Fluids	82
13	Assigned Efficiencies of Various Treatment Systems for Removing Gross Constituents	82
14	Capital Costs for Injection Systems at Four Well Capacities	95
15	Operating Energy Costs for Injection Pumps	97
16	Cost of Ocean Disposal of Geothermal Wastewaters	98
17	Estimated Water Surface Area Required for Disposal of Geothermal Plant Wastewaters	99
18	Estimated Maximum Hydraulic Loading of Wastewater Effluent for Various Soil Conditions	101
19	Annual Cost of Disposal of Geothermal Wastewater by Land Spreading	102

I. SUMMARY AND CONCLUSIONS

PERSPECTIVE

The total geothermal resource in the United States is immense, but its exploitation is technologically and economically limited to geologically anomalous areas where high temperatures are very near the surface. Geothermal energy will contribute a relatively small fraction of the nation's total energy requirement in the foreseeable future. However, locally and perhaps regionally, its contribution may be very important, particularly in the western and southwestern United States before the turn of the century.

The magnitude of pollution problems resulting from geothermal exploitation is directly related to the scope of development. Discharges from geothermal activities are not foreseen as threats to the national health and welfare, but may well be locally significant.

A major part of the current development effort is directed toward electric power generation from high-temperature, liquid-dominated geothermal systems. Less effort is directed toward development of direct heating uses, even though those uses are more energy-efficient. With increasing knowledge of the exploitable potential, the emphasis may shift.

Only one commercially operating geothermal power field exists in the United States, the 11-unit 502 MWe station at The Geysers, California. It is probably atypical of future plants because it utilizes dry steam, a relatively rare type of resource. The steam is nearly pure, but hydrogen sulfide emissions have caused much local concern with the odor problem and resulted in delays to plant expansions. At the other end of the spectrum, much effort is being directed to development of California's large Imperial Valley geothermal resources which are characterized by high salinity liquids, with the highest thus far encountered in the Niland field. The great bulk of the exploitable geothermal resources probably lies somewhere between The Geysers and the Imperial Valley resources in pollution potential.

In favor of the continued expansion at The Geysers and the intense development in the Imperial Valley is the probability that successful demonstration of control of their present and potential pollution problems will contribute greatly to successful environmental control at all other future sites.

EPA REGULATORY APPROACH

The Federal EPA regulatory approach for the geothermal industry will be directed toward the following goals by the time the geothermal industry reaches a stage of significant commercialization.

Precommercialization Regulation

Prior to the establishment of formal regulations, during the geothermal development phase, geothermal discharges will be controlled through the issuance of permits, as prescribed by Federal law, on a case-by-case basis, the conditions of which will be determined by existing ambient standards, known or expected effects, state-of-the-art control technology, and environmental impact review. Periodic guidance will be issued by EPA with respect to these factors, beginning with this document.

Surface Water Protection

Technology-based Effluent Guidelines, including National Standards of Performance, will be established under Sections 301, 304, 306 and 307 of the Federal Water Pollution Control Act Amendments of 1972. Consideration will be given, as required by the Act, to the elimination of all pollutants, where technologically achievable.

Water Quality Standards, applicable to receiving waters, will be revised, where necessary, under Section 303 of the Federal Water Pollution Control Act Amendments of 1972. Revisions may include additional pollutants. It is possible that some additions may result from pollutants having been found in geothermal wastes in environmentally harmful concentrations.

Ground Water Protection

Current regulations under Part C of the Safe Drinking Water Act are not applicable to subsurface disposal of spent geothermal fluid. If and when applicable regulations are promulgated, they are likely to include injection system design requirements and pre-operational approval of designs. Regulations would probably prevent injection of spent fluid contaminants to designated drinking water aquifers and would probably require injection to or below the producing reservoir where economically and technologically feasible. Where not feasible, injection would probably be limited to saline, nonpotable ground waters; this may be the case in geopressured resource areas.

Regulations will be established under the Resource Conservation and Recovery Act that will be applicable to surface brine and/or sludge impoundments at geothermal facilities, primarily to prevent infiltration of contaminants to ground waters. The regulations will also protect surface waters from contamination by impoundment runoff. The regulations will include system design requirements and pre-operational design approval.

Air Quality Protection

New Source Performance Standards (NSPS) will be established under Section 111 of the Clean Air Act and Section 109 of the Clean Air Act Amendments of 1977, for emissions from geothermal energy conversion facilities. Emissions of specific gases, such as hydrogen sulfide, will be NSPS-regulated. NSPS regulations are technology-based; thus the approach will include support for technology development to minimize environmental effects.

Although the option is available, it does not presently appear likely that any of the gases emitted from geothermal facilities will be regulated by the effects-based ambient air quality criteria and ambient standards under Sections 108 and 109 of the Clean Air Act and Section 106 of the Clean Air Act Amendments of 1977, or by the hazardous air pollutant provisions of Section 112 of the Clean Air Act and Section 110 of the Amendments of 1977.

Section 122 of the Clean Air Act Amendment of 1977 provides for the regulation of emissions of radioactive substances, cadmium and arsenic, all of which may be found in geothermal fluids. Emissions of these substances from geothermal facilities are likely to be regulated if they are found to be in environmentally significant quantities.

Noise Protection

Noise will be regulated by EPA under the Noise Control Act of 1972 if a product used in geothermal energy development is identified as a major source. Other sources of noise will be regulated by state and local agencies with EPA providing guidance as necessary. EPA will exercise its authority, where necessary, to ensure that federal geothermal facilities meet all appropriate federal, state and local noise regulations, including standards imposed by the Occupational Safety and Health Administration (OSHA).

Radiation Protection

Radioactivity in geothermal fluid discharges and emissions will be regulated, where necessary, like chemical pollutants, by inclusion in guidelines and standards under the provisions of the Federal Water Pollution Control Act, the Clean Air Act, and the Safe Drinking Act, as described above.

GEOHERMAL POLLUTANTS AND SOURCES

The principal geothermal pollutants, all of which originate in the geothermal reservoir, are dissolved chemical constituents, "non-condensable" gases, and heat. None of the components, except heat and its water medium, is necessary to the operation of an energy conversion system. All will be discarded unless mineral recovery is practiced.

Spent geothermal waters will range from low (<1000 ppm) to very high (>250,000 ppm) salinity and may include many inorganic constituents, such as metals, in hazardous concentrations. Spent water from most areas is

expected to be comparable to or lower than sea water in salinity. Generally, the most contaminated waste water will be discharged from electric power generation facilities operating from high temperature, saline, liquid-dominated reservoirs. Discharge volumes may range up to 70,000 liters/megawatt-hour at temperatures of about 50°C (120°F). In-plant sources of waste water at power generation facilities will be steam-water separators, residual from flashing water to steam, cooling water and condensate. Unplanned releases of large volumes of geothermal fluid are possible during system failures in the plant or in the production well and distribution network.

The least contaminated waste waters are expected to be from non-electric applications using lower temperature and less saline geothermal waters. Discharges can be expected of the total fluid at the end of the heating system with temperatures of 30°C (85°F) or less. Volumes will likely be relatively low and the waters may in some cases be further used as water supplies.

"Non-condensable" gases, those which do not condense at system operating temperatures, are also expected to be of greater pollution significance in power generation, with hydrogen sulfide continuing to head the list because of its offensive odor at low concentrations. Others may come to the fore, such as ammonia, radon, and mercury. The non-condensable gases will emanate principally through condenser gas ejection, cooling tower exhaust, power plant bypassing during plant shutdown, and well venting. Hydrogen sulfide is currently a problem at The Geysers station, and is likely to be also at plants operating on steam flashed from hot geothermal water.

Most non-electric uses of geothermal energy are likely to result in more intimate contact with the user. It is conjectured that this aspect may prevent a particular non-electric use of geothermal fluids having significant gas content. In cases where steam may be flashed from the water, such as in large process heating uses, the problems would be similar to those from power generation.

Solid wastes, sludges, and/or concentrated brines, may result from treatment to remove certain geothermal fluid constituents. Spent drilling muds and well cuttings also constitute solid wastes, as do removed soil and wasted construction materials; drilling muds may contain hazardous chemicals.

Disturbances of the land surface, necessary in the development of a geothermal field, can result in the destruction of wildlife habitat. Sediment runoff from such disturbances can disrupt or destroy fish habitats in nearby streams.

Noise can be severe, requiring ear protection of nearby workers, from air drilling operations and venting of steam and water from wellheads and distribution systems. Although there are other noise sources, drilling and venting are over-riding.

ENVIRONMENTAL CONCERNS FROM GEOTHERMAL POLLUTANTS

Water Pollutants

Water Quality Standards of the fifteen states with known geothermal potential are not uniform. While six of the states include many of the chemical pollutants that have been found in geothermal waters, none of the states include all of them, and six states include none of the specific chemical constituents.

The environmental effects of many of the constituents characteristic of geothermal waters have been determined through past research by EPA and others. This work has formed the basis for Water Quality Standards and suggested water quality criteria. Most of the effects work has emphasized the acute and chronic toxicity of various chemical elements and compounds on aquatic organisms, including fish. Health effects on humans by consumption, through water supplies, have been principally inferred from that work, but with some reliance upon studies of the results of unintentional or accidental human ingestion. The paucity of standards for agriculture indicates little emphasis in that area.

Geothermal waters are not normally sources of organic constituents. The pollutants of greatest concern are heavy metals. While most geothermal waters may contain few if any in significant concentrations, all will contain measurable amounts of several metals. Some geothermal waters, particularly those with high salinity, contain a few or many metals in concentrations hazardous to humans, animals, and/or plant life.

Generally, the hazards of metals to all life forms include chronic and acute toxicity, interference with reproductive capacity, and interference with growth rates. Several constituents that have been found in geothermal fluids may be suspected of having similar effects but have been omitted in standards and criteria development for one or more uses.

High dissolved solids (salinity) content makes water unacceptable for human consumption. Regardless of the precise chemical composition, high and/or prolonged salinity can be toxic to terrestrial plants and aquatic life not acclimated to it, by interference with normal osmotic conditions.

Waste heat in spent geothermal waters, if allowed to enter surface waters, is potentially dangerous to aquatic life, e.g. excessive temperature can halt fish reproduction. Sensitivity of most desirable aquatic life species to temperature change is amplified by the fact that the optimum growth temperature is usually only a few degrees less than temperatures destructive to physiological well-being.

Air Pollutants

Most of the non-condensable gases or vapors that have been found in geothermal fluids are innocuous and are normal components of the atmosphere. Some, however, are not normally significant atmospheric components. Of these, hydrogen sulfide is currently of most concern.

Unlike water pollutants, where effects investigations emphasize aquatic life, air pollutant studies have emphasized effects of inhalation on humans, as have resulting standards.

Hydrogen sulfide is unique among geothermal air pollutants in that its control has been principally forced by its odor rather than health effects. Although it can have local health effects in the quantities emitted from geothermal facilities, the difference between offensive odor concentrations and toxic concentrations to humans is several orders of magnitude.

Increasing hydrogen sulfide concentrations result in varying responses. At less than 0.1 ppm it has a very offensive odor but otherwise appears to be innocuous to humans. At about 1 ppm it can cause nausea and headaches. At 100 ppm to 200 ppm it can cause a loss of the sense of smell, and near 700 ppm death may result quickly due to respiratory paralysis.

Obviously the health effects of hydrogen sulfide are potentially much greater in the facility occupational environment than in off-site areas. Occupational Safety and Health Administration regulations list an acceptable, continuous ceiling concentration, in the workplace of 20 ppm, and lower concentration limits are being considered.

Regulation of other air emissions from geothermal facilities may be supportable in the future as more data are accumulated. Those most likely to be considered, on the basis of their known presence and possible effects, are ammonia, mercury, arsenic, and radon.

Boron, in the form of boric acid, although principally a concern in water discharges, may be emitted in cooling tower drift and cause harm selectively to leaf growth of local vegetation. Citrus crops are particularly sensitive to boron.

Noise

The effects of noise are functions of intensity and exposure time. In the immediate vicinity of geothermal operations both can be large. The effects of noise can be physiological or psychological, or both. They can range from simple annoyance in an otherwise quiet setting, to stress reactions, to hearing loss under high intensity conditions. All could occur as a result of noise from geothermal activities, with annoyance the probable major problem outside the facility's boundaries. The United States Geological Survey has imposed noise restrictions upon geothermal operations on federal lands. They specify a maximum level of 65 dBA at the lease boundary or a distance of one-half mile from the source, whichever is greater.

Land-Disposed Wastes

The principal effects of pollution from land-disposed geothermal fluid-derived solid or brine wastes would be similar to those summarized above under Water Pollutants, since contamination would result from leachate runoff and/or percolation to groundwater.

Radiation

Radionuclides are known carcinogens and no level is accepted as being non-damaging. The effects upon man are of greatest concern, and may occur as a result of inhalation or food ingestion. No effects have been shown as attributable to radionuclides released by geothermal operations; radon gas specifically may be a potential hazard in some areas.

POLLUTION CONTROL TECHNOLOGY

Very few pollution control technologies applicable to geothermal energy conversion systems have been demonstrated. Most of the control technology development and operation of control facilities has been done at The Geysers geothermal power generation station owned by the Pacific Gas and Electric Company.

Several pollution control technologies used in other industries appear to be applicable to the geothermal industry, if they are sufficiently economical. However, at present, it appears that many of them will not be economically achievable in situations where they might be technically feasible. It does not appear at this time that any new control technology concepts will be devised for the geothermal industry. Instead already known concepts and their technologies will be adopted.

Air Pollution Control

Two technologies for application to spent geothermal fluid have been demonstrated at The Geysers power station. Each removes 90% or more of the hydrogen sulfide reaching the treatment system. One is a regenerable iron catalyst system applied to the cooling tower exhaust, to which condenser ejector gases are also directed. This system, which can be used with direct contact condensers, produces large quantities of sulfur-rich, but unusable, sludge that must be land-filled. The second technology, called the Stretford process, is applied to the condenser ejector gases only, and requires the use of surface condensers. This process also uses regenerable catalysts, but produces high quality sulfur that may be saleable.

Two "pre-treatment" processes are currently being tested at The Geysers to remove hydrogen sulfide from the steam before it reaches the turbine. Both may be successful. One, developed by EIC Corporation, uses regenerable copper sulfate, and the other, developed by Deuterium Corporation, is proprietary. Pre-treatment would be desirable in preventing downstream corrosion and scaling of power plant equipment. Pre-treatment would also provide treatment when steam must by-pass the plant during shutdown periods and would eliminate the possibility of leaks from the power generation process escaping treatment.

Escape of gases during well and pipeline venting is not now controlled other than by minimization of flow. Collection and treatment schemes need to be developed for these losses.

Hydrogen sulfide removal from flashed steam derived from liquid-dominated resources should not present unique problems. Technologies employed at The Geysers should be directly applicable. Those using regenerable catalysts appear to be the most economically feasible. Dow Chemical USA has shown the technical feasibility of treating geothermal water prior to flashing by an oxygenation process.

Treatment technologies have not been applied or developed for other possible air pollutants from geothermal facilities. Additional air pollutants may have to be considered if they are shown to cause significant environmental problems. Such technologies may include exclusion areas to allow for dispersion.

The table below summarizes preliminary capital and operating cost estimates for existing and experimental geothermal H₂S control technologies.

SUMMARY OF ESTIMATED ANNUAL AIR
POLLUTION TREATMENT TECHNOLOGY COSTS

Process	mil/kwh @ 10 MWe	mil/kwh @ 100 MWe
Stretford	1.9	0.45
Iron Catalyst	1.2	0.4
EIC Process	4	2
Dow Oxygenation (in-line system)	10	8
Dow Oxygenation (packed column)	9	7.5

Water Pollution Control

The two principal types of waste water from geothermal operations, spent geothermal liquid and cooling water, will in most cases require treatment if they are to be discharged to surface waters. Some low-salinity waters used in non-electric applications may be clean enough to discharge to fresh surface waters without treatment, except perhaps for cooling.

Surface pollution treatment technologies, except for cooling, will be principally aimed at removal and disposal of dissolved solids and their toxic components. None has yet been demonstrated for geothermal applications on a large scale. However, several technologies are available, including evaporation, membrane filtration, and ion exchange. All are costly for

large-scale application and would probably not be economically feasible for geothermal operations unless they result in a saleable byproduct.

The following table summarizes preliminary capital and operational cost estimates for potentially applicable wastewater treatment technologies.

SUMMARY OF ESTIMATED WASTEWATER TREATMENT TECHNOLOGY COSTS

Process	\$/1000 liters @ 10 lpm	\$/1000 liters @ 100,000 lpm
Sedimentation	2.50	.01
1-stage lime addition	4.50	.02
2-stage lime addition	6.00	.01
Alum addition	4.50	.06
Ferric chloride addition	6.00	.07
Filtration	1.10	.06
Ion exchange	.30	.09
Reverse Osmosis	.30	.12
Electrodialysis		.30
Vapor compression evaporation	.60	.20
Multieffect evaporation	.90	.50
Multistage evaporation	.90	.50

Wastewater disposal, other than directly to surface waters, may require less treatment and includes several alternatives such as subsurface injection, ocean disposal, evaporation ponds, and land spreading.

Injection to the geothermal reservoir with no surface water discharge appears, in most cases, to be the most practicable and environmentally acceptable disposal method for spent geothermal brines, cooling water blowdown, and excess condensates. Injection not only would solve the water disposal problem, but might minimize reservoir depletion and potential surface subsidence. Injection of relatively clean excess condensate has been practiced successfully for several years at The Geysers. Injection of brines is being tested more or less successfully at several experimental sites in the Imperial Valley. System corrosion, scaling, and formation plugging are potential problems, although apparently not insurmountable,

with higher salinity fluids. Impervious ponds can be provided to contain unplanned surface losses which might occur with system rupture.

Ocean disposal may be acceptable in some cases where access is available, and the brine will not significantly contaminate sea water and coastal zones. However, costs may be prohibitive, particularly where significant transport distances and/or prior treatment are required.

Evaporation ponds can be very effective, but also very costly, for large volume disposal because of the land area required. Land spreading may be inexpensive, but will be limited because of the probability of salt accumulation in soils.

The following table summarizes estimated costs of wastewater disposal by various methods.

SUMMARY OF ESTIMATED COSTS OF WASTEWATER DISPOSAL

Method	\$/1000 l @ 1000 lpm	\$/1000 l @ 100,000 lpm
Injection	.10 - .15	.02 - .10
Ocean Disposal (200 mi. from plant)	.52	.33
Evaporation Ponds	.25	.13
Land Spreading	.02	.02

Cooling towers or ponds can be used for excess heat removal from cooling waters. Closed cycle operation of such facilities may in fact be demanded in water-short areas, where cooling water must be recycled.

Land-Disposed Waste Control

Land-disposed wastes and surface brine impoundments must be totally and permanently isolated from ground waters, if hazardous materials are included. Site selection and landfill methods and impervious liners should be generally available and adaptable to geothermal wastes. Off-site disposal at control agency approved sites will often be necessary. It is estimated that disposal at a site 200 miles distant would cost about \$21/metric ton.

Noise Control

Noise can be controlled by a variety of attenuating devices, all of which appear amenable to further improvement. Mufflers for escaping air and steam, the most intense noise sources, range from rock-filled barrels to large expansion towers. Noise can also be attenuated by distance, barrier walls, topography, and vegetation.

II. RECOMMENDATIONS

The following recommendations should be considered as initial pollution control guidance with respect to discharge and emission limits, pollutant monitoring, and control technology and regulatory development needs.

SUGGESTED POLLUTANT LIMITATIONS

Air Emissions

Hydrogen sulfide is the only air pollutant for which limitations are suggested at this time. Hydrogen sulfide emissions from initial demonstration facilities and existing commercial facilities should be limited to an average of no more than 10% of the loading in the raw fluid. For most electric power generation facilities it is expected that this will be equivalent to an average between 0.2 and 0.4 kilograms per megawatt-hour (MWH) of normal power generation (rated capacity X plant factor). Facilities producing raw loads less than 0.2 kg/MWH probably will not require treatment.

For non-electric uses where hydrogen sulfide may require control, limits, comparable to those suggested for power generation, are suggested to be within the range of 20 to 40 kg H_2S per million kg of steam used. The basis for such emission limitations is an economically achievable treatment level, rather than environmental effects. However, with the present state of knowledge, it is expected that the suggested emission levels will have little if any measurable environmental effect. The basis for this expectation is The Geysers experience in which the principal known problem caused by unabated emissions is an odor nuisance; a 90% reduction in emissions should essentially eliminate this problem.

Emissions of other gases and particulate materials from geothermal operations may be anticipated, although the evidence of need is currently inadequate to justify their control.

Water Discharges

Where geothermal spent liquids contain pollutants in excess of surface receiving water standards for the area, a no discharge limitation is suggested, unless the liquids are treated to meet those standards at the discharge point. Further, it is suggested that injection to the geothermal reservoir be practiced, and that it be regulated so that other usable ground water aquifers are not changed in chemical or physical properties. In cases where it is not economically feasible to return the spent fluid to the producing reservoir, such as may be the case with geopressured resources,

injection to other aquifers may be allowed if the injected fluid does not degrade those aquifers for other existing or potential uses. It is recognized that spent fluids will in most cases contain higher constituent concentrations than the originally withdrawn fluid. A concentration increase, caused by injected fluids, should be allowable in the geothermal reservoir to the extent that it does not interfere with other legitimate uses of the reservoir waters. In some cases this may require that the state (or EPA where a state declines primacy) designation of certain geothermal reservoirs for geothermal use only.

Land-Disposed Wastes

Suggested limitations for geothermal solid wastes containing hazardous materials (including fluid constituents) are containment and isolation from possible leaching to ground or surface water, or treatment of leachate to remove hazardous materials and any materials that, if discharged, would violate water quality standards.

Noise

Noise limitations should conform, as an initial minimum, to the regulations issued by the U.S. Geological Survey for geothermal operations on Federal lands; i.e. not to exceed 65 dBA at the lease boundary or one-half mile from the source, whichever is greater.

MONITORING

All air emissions, water discharges, and noise should be monitored by the operator on a periodic schedule for all pollutants having a potential harmful effect. In addition, the operator should carry out ambient monitoring at appropriate points at the boundary with other public or private property for the same pollutants, both before (baseline monitoring) and during conversion facility operation, to assure that standards are not violated and harm does not occur, especially where several facilities are co-located.

CONTROL TECHNOLOGY AND REGULATORY DEVELOPMENT NEEDS

It is recommended that all agencies and private industries concerned with geothermal research and development cooperate fully, including the free exchange of information, in developing further the pollution control and monitoring strategies and technologies described briefly herein. Detailed technical and economic analyses should be cooperatively pursued and documented.

It is recommended that increased attention be given to geothermal fluid characterization, to the determination of pollutant effects on the environment, and to the development of reliable injection technologies.

The solutions to many of the conversion technology problems should be evaluated to determine which can simultaneously provide solutions to environmental problems.

III. INTRODUCTION

OBJECTIVES

The objective of this document is to provide pollution control guidance to geothermal energy developers and regulators. Ranges of constituent limits in air emissions and water discharges are suggested where possible. The suggested limits may be viewed as serving three purposes: (1) to provide assistance in developing discharge and emission permit conditions for specific exploration, development, demonstration, and prototype facilities; (2) to define goals developers can expect and plan for with some confidence; and (3) to take the first step toward development of equitable and enforceable standards for the geothermal energy conversion industry.

BACKGROUND

Standards Problem

Under the auspices of the U.S. Energy Research and Development Administration (ERDA--now the Department of Energy), the Interagency Geothermal Coordinating Council (IGCC) (formerly Geothermal Advisory Council) was established to coordinate interagency activities relating to geothermal energy development. The Institutional Barriers Panel of the Committee defined several issues in a report dated June 30, 1976.¹ One of the issues resulted in EPA producing this document. Essentially the report stated that, in the absence of Federal standards, the States could set varying standards that would complicate and add cost and uncertainty to geothermal technology development. Immediate action was recommended to establish, within one year, interim Federal guidelines for geothermal emissions.

Subsequent discussions resulted in a commitment by the Administrator of EPA to produce a draft guidance document by July 1, 1977. This document is the result of the EPA commitment. The Administrator decided that formal regulatory guidelines could not be produced without the existence of an established industry.

Although the IGCC inferred that air emission standards are of greatest concern, this document considers all potential pollution areas--air, water, solid wastes, radiation, and noise.

Perspective

The total potential geothermal energy resource is immense; however, its availability for economical exploitation by existing technology is

small compared to that total. Over most of the earth's surface, temperature increases rather uniformly and modestly with depth, averaging about 25°C/km.² Exploitation with present technologies can occur only in naturally anomalous situations that allow heat to move rapidly toward the surface and/or to be trapped at shallow depths. Anomalous conditions occur typically in areas of recent crustal disruption where folding, faulting, magmatic intrusions, and volcanism provide avenues for higher outward heat transport. In the United States such areas are generally found from the Rocky Mountains westward. An exception is the geopressured area of the Gulf Coast, which appears to be a large stable region of simple entrapment of normal outward heat flow. Search for and characterization of geological anomalies leading to commercially developable geothermal resources are basic first steps of geothermal investigation.

Several factors presently limit the exploitability and potential uses of a geothermal resource. These include temperature, the depth to the resource, the content of water and its long-term availability, the form of the water (liquid or vapor) and its pressure, and geographical location. The most desirable characteristics with respect to these factors are rather obvious, namely, hot, shallow, high-pressure steam in large volume near an energy load center. The search for these desirable characteristics has placed an emphasis on electric power production, although such energy conversion is much more inefficient than direct heating applications. Recognition of the inefficiencies may serve to change the emphasis, tempered by the remoteness of much of the resource from populated areas.

Recent ERDA estimates³ project a geothermal contribution equivalent to 6,000 MW (megawatts) by 1985 and 39,000 MW by the year 2000, given a successful federal implementation program. For comparison, current electrical production in the United States is about 400,000 MW.

Most of the geothermal energy production, between now and the year 2000, will probably be from hot water resources. Vapor-dominated resources are apparently rare, even though the major production at The Geysers in California, the only present U.S. power generation application, is from this type. Geopressured resources are not likely to make a major contribution in the period cited by ERDA unless their natural gas content becomes exploitable.

The total waste water flow resulting from ERDA-projected energy production would be in the range of 4×10^9 to 8×10^9 liters/day (1,000-2,000 mgd) in the year 2000. Flows would be of the same order of magnitude as the once-through cooling water requirement for equivalent fossil-fueled electric power generation.

The method chosen for disposal of spent geothermal liquids will not be determined solely by pollution control reasons, particularly in power generation. In general, power generation will entail a long-term commitment at one site with sufficient high-temperature resources to maintain consistent production for at least 30 years. It is likely that in most places the rate of water withdrawal will significantly exceed natural replenishment; resource conservation is therefore desirable. The most

feasible way to accomplish this is by returning the spent liquid to the reservoir. It is also possible that subsidence will be induced by high-volume withdrawal; injection may minimize this possibility. At the same time, injection to the reservoir would also minimize the likelihood of pollution. Both withdrawal and injection may affect seismicity by increasing or decreasing the risk.

If the emphasis in geothermal development changes more toward direct heating applications, the choice of disposal methods may also change. A broader range of temperatures may be utilized. The lower temperature resources, suitable for heating, may not require injection for reservoir maintenance; in many places natural recharge may be sufficient. In these cases, injection might be considered solely as a disposal method to prevent pollution. If the residual water does not require treatment for surface disposal, it may serve as a water supply for other uses after heat extraction.

For purposes of establishing a perspective, it can be stated that power generation is usually sought first because electricity can be transported easier than heating fluids, from the generally remote geothermal areas, and that, although vapor-dominated (steam) resources are the most desirable, liquid-dominated (hot water) resources will prevail because of their greater abundance. The hottest resources will be developed first if power generation is the goal. Because of their usually higher salinities, high temperature liquid resources can potentially cause greater pollution problems, but they will probably be injected back to the reservoir. At the present time, major development activity is proceeding in the Imperial Valley, California, which apparently contains the highest salinity sources in the United States. Other areas of lesser salinity are in various stages of exploration.

All geothermal sources appear to contain dissolved gases that may prove to be, overall, the most troublesome pollutants. They must be removed in most power generation operations because they interfere with steam condensing. When removed, they must be disposed of, and some will require treatment. Unlike water, they cannot normally be injected.

In terms of national impact, geothermal energy conversion does not pose a major environmental threat. Local impacts could in some cases be severe; however, there is every reason to believe that potential pollution will be economically controllable in most, if not all, cases.

EPA GEOTHERMAL POLLUTION CONTROL REGULATORY APPROACH

The pollution control regulatory approach being adopted by EPA⁴ has been selected from the options available under EPA-administered laws. The appropriate sections of those laws are summarized in the Appendix. Parts of several other Federal laws, requiring or related to geothermal pollution control, are also summarized in the Appendix. In addition, the Appendix discusses briefly the interaction of State and Federal laws.

The regulatory approach selected by EPA is designed to relate to the DOE development, demonstration, and commercialization schedule.^{3,5} The regulatory objectives are to:

- (1) establish point source emission and discharge limitations for environmentally damaging constituents by the onset (after 1981) of significant commercialization;
- (2) provide guidance, periodically updated up to the time of significant independent commercialization (through the development and demonstration phases), on limitations that can be anticipated prior to facility construction, through the application of ambient standards and state-of-the-art control technology;
- (3) minimize to the extent possible, by way of the same periodic guidance, uncertainties in emission and discharge requirements;
- (4) develop and evaluate information, which supports guidance and regulations, throughout the precommercialization stage, in concert with the industry and other involved governmental agencies; and
- (5) regulate geothermal pollution throughout the precommercialization period by application of the emission and discharge permit systems, which may be State-administered, with permit conditions based upon ambient standards, known or expected effects, state-of-the-art technology, and environmental impact review. Periodic guidance will be issued by EPA with respect to these factors, beginning with this document.

Air Pollution

The EPA will direct effort toward the establishment of New Source Performance Standards under Section 111 of the Clean Air Act for those pollutants that may have significant harmful effects. The most obvious one of those pollutants at the moment is hydrogen sulfide. That constituent and others are described more fully in Sections II and III of this document. Controlled pollutants may include radioactive as well as the more ordinary chemical constituents.

It should be emphasized, however, that New Source Performance Standards would be technology-based, rather than effects-based. However the EPA approach will include support for technology development to minimize environmental effects. The States would still have the option of imposing more restrictive limitations. EPA would retain the option to set Ambient Air Quality Standards and Hazardous Air Pollutant Standards, should health and environmental effects data later prove the need.

Water Pollution

EPA will develop information looking toward the development of Effluent Guidelines and National Standards of Performance under Sections 304 and 306 of the Federal Water Pollution Control Act for surface water discharges from geothermal facilities. These guidelines and standards will eventually provide firmly based effluent limitations and thus NPDES permit loadings. Consideration will be given, as required by the Act, to the elimination of all

pollutants, where technologically and economically achievable. The effluent limitations will be available by the onset of full-scale commercialization of most conversion technologies. This is estimated to be after 1981.

In the interim, the principal base for control will be receiving water quality standards (40 CFR Part 120) now in existence, which are periodically revised and upgraded. Revision may include additional constituents, some of which may be unique to geothermal operations. Water quality standards are established by the States in concert with EPA. Such standards include chemical, physical, and radioactivity criteria to support designated uses and frequently result in NPDES permit conditions more restrictive than those based upon effluent guidelines. The 1983 goal of the Act is to provide water quality that will support fishing and recreation in and on the water.

The EPA approach to subsurface disposal regulation is of particular importance to geothermal development, since many, if not most, processes will probably include injection of spent fluids. When geothermal injection regulations are promulgated by EPA, they will likely require the prior approval of detailed system plans and designs on a case-by-case basis. Also, drinking water aquifers are likely to be defined or designated, and degradation of those aquifers will not be allowed. Most States and the U.S. Geological Survey (under the Geothermal Steam Act) already have regulations requiring prior approval of injection system designs.

The EPA will also utilize "Administrator's Decision Statement No. 5," which established EPA policy with respect to injection wells. It requires strict controls and their evaluation where injection is included in any activity in which EPA has any control. Also, surface water discharge (NPDES) permits are required if waste water treatment, to facilitate injection, results in surface discharges. On Federal lands, the U. S. Geological Survey may apply these and its own existing requirements (GRO Order No. 4, Section 9C)⁶ to geothermal reinjection.

Land-Disposed Wastes

Substantial regulatory authority by EPA for the control of land-disposed wastes has just recently been provided by the Resource Conservation and Recovery Act of 1976, for which regulations have yet to be established. However, it is certain that any geothermal activity that uses surface impoundments to store, treat, or dispose of potentially hazardous waste, or that produces solid wastes will be subject to guidelines and regulations, and operating permits will be required by the States. Most States already have applicable regulations. Wastes containing toxic, and/or radioactive constituents will be particularly restricted, and detailed records of their history through ultimate disposal will be required.

Noise

The EPA has the authority to ensure that Federal geothermal activities meet all applicable Federal, State, and local noise regulations and do not seriously impact the public health and welfare. EPA recognizes that noise is a significant concern in geothermal development. EPA's support of U.S.

Geological Survey noise regulations applied to geothermal developers on Federal lands will depend on whether those regulations are adequately protective of the public health and welfare. Some States have similar regulations for State-owned lands. EPA will recommend limits of environmental noise required to protect health and welfare to the regulatory programs of other agencies.

Radiation

The "Standards for Protection Against Radiation" (10 CFR 20) that form the basis for EPA's guidance to the Nuclear Regulatory Commission do not apply to geothermal energy. This is because 10 CFR 20 is limited to the component materials and by-products of a nuclear fission reaction, under the Atomic Energy Act of 1954. EPA does have authority to regulate radiation aspects of geothermal energy under the Clean Air Act, Federal Water Pollution Control Act and the Safe Drinking Water Act. The options for such actions are the same for radiation as for chemical problems in air and water pollution.

EPA acts in an advisory capacity to other Federal agencies in writing their own internal regulations regarding environmental radiation impacts. EPA has utilized the numerical limits originally set by the Federal Radiation Council for individual doses, but these are not considered particularly restrictive, because radiation exposure can usually be made much lower without significant economic penalties. In addition to the numerical bounds, EPA provides qualitative guidance, to ensure that adequate controls are provided. Because there is no known radiation level at which zero impact exists, qualitative guidance has been to require that radiation doses be kept as far as practicable below the numerical limits. Practicability is judged by a cost/benefit analysis that addresses the effectiveness of the control technique, and includes the impact of the anticipated radiation level as a cost.

IV. GEOTHERMAL POLLUTANTS AND PROCESS SOURCES

The overwhelming preponderance of pollutants from geothermal energy conversion operations will derive from the geothermal fluid itself. Other potential pollutants, such as added chemicals, and materials emitted during exploration, development, and facility construction phases, are expected to be comparatively minor or transient in nature.

Geothermal fluids and the contained energy are expected to be utilized in many ways, including electric power production, space heating, industrial process heating, agricultural drying, and even water supply. By far the greatest volume of geothermal fluid is expected to be from liquid-dominated resources used for electric power production. The raw and spent fluids in power production from liquid-dominated resources are also likely to contain higher quantities of chemical contaminants and heat.

Regardless of the end uses, the processes and activities preceding these uses will have many similarities. Pollution sources can generally be subdivided into:

- Wellfield exploration, development, and construction activities.
- Fluid distribution and energy conversion system operations.

Each of these categories is discussed further in the following subsections.

WELLFIELD EXPLORATION, DEVELOPMENT, AND CONSTRUCTION ACTIVITIES

This category of sources can be further subdivided into the following:

- Access clearing and preparation
- Drilling
- Construction of fluid distribution and conversion facilities.

All of these sources are considered, with reasonable management, to be transient pollution sources and of minimal consequence in the overall geothermal development picture. Many of the pollutants may be significant for short periods and may not be totally controllable, especially those classed as fugitive emissions (released without control of flow or direction), such as road dust. Most pollutants are generally considered more as nuisance-creating than as hazardous contaminants. The drilling and construction

activities and their associated surface disturbance have been well described in a preliminary report⁷ prepared by the U. S. Geological Survey.

Access clearing is a part of all geothermal development, from exploration through plant construction. Soil and vegetation are disturbed or destroyed and replaced by roadways and pipeline clearings. Pollutants are dust and waterborne silt, vegetation debris, and machinery noise and exhaust. Drilling site preparation includes the same pollutants.

The drilling process itself has the potential for more serious environmental contamination from the loss of drilling muds and possible well blow-outs. Such releases are accidental, but are almost totally preventable with present-day drilling practices.

Drilling muds may be comprised of various constituents such as bentonite, barite, and perhaps chrome-lignite or chrome lignosulphonate, and sodium hydroxide.⁸ Proprietary constituents may be included. Drilling mud disposal is generally subject to strict State solid waste regulations. Well cuttings may be subject to the same regulations.

Well blowouts can contain any or all constituents of the geothermal fluid, described later in this chapter.

Equipment operation during drilling can cause very high noise levels, particularly when compressed air is substituted for drilling mud, generally during the later stages of drilling.

Construction of fluid distribution and energy conversion facilities is similar to construction of most other industrial facilities, as are the associated pollutants. The pollutants derive from debris, runoff erosion, construction materials, and machinery operation. Soil dust, other airborne particulates, waterborne suspended solids, and noise are the principal pollutants. Most pollutants are generally considered to be in the non-point source and fugitive emissions categories.

FLUID DISTRIBUTION AND ENERGY CONVERSION SYSTEM OPERATIONS

The principal pollutants, after the conversion facility is in operation, will derive from the geothermal fluids as they pass through the facility. Environment-contaminating discharges can potentially occur at the following sites within distribution and conversion systems.

- Wellhead (initial and periodic full-flow venting).
- Fluid phase separation (liquid phase wasting).
- Pipeline vents (continuous small stream venting).
- Steam scrubbing (venting of particulates).
- Steam condensation (condensate discharge).

- Condenser gas ejection (venting noncondensable gases).
- Cooling towers (condensate drift).
- Cooling water discharge, with or without recycle.
- Air and/or water waste treatment (sludge and treated water and air discharges).
- Injection system (all or part of fluids returned to subsurface).

In some proposed systems, one or more of the listed sources will not exist, while in others all can be significant. The proportion that each of the sources contributes to the total discharges, and to the discharges to each medium (air, surface water, land, and subsurface), depends upon many factors. These factors include the type of conversion systems; the initial fluid state (temperature, pressure, and composition), cooling water source; cooling method; and whether waste water injection is practiced.

From an environmental standpoint the production of electrical power is likely to be the most significant near-term use of geothermal energy. In turn, the greatest pollution potential will likely be from moderate to high salinity liquid resources, in which up to 70,000 liters/megawatt-hour would be discarded as spent liquid. A facility in such a resource area might be as schematically shown in Figure 1, with potential pollution release points as depicted. This might be considered environmentally as a worst-case example where all releases would be directly to the air and surface drainage. Both ends of such a plant would have continuous discharges, from the wellhead separator and from the condenser, the latter being cooled by an external water supply. Condensate and cooling water discharges would constitute by far the largest pollution source.

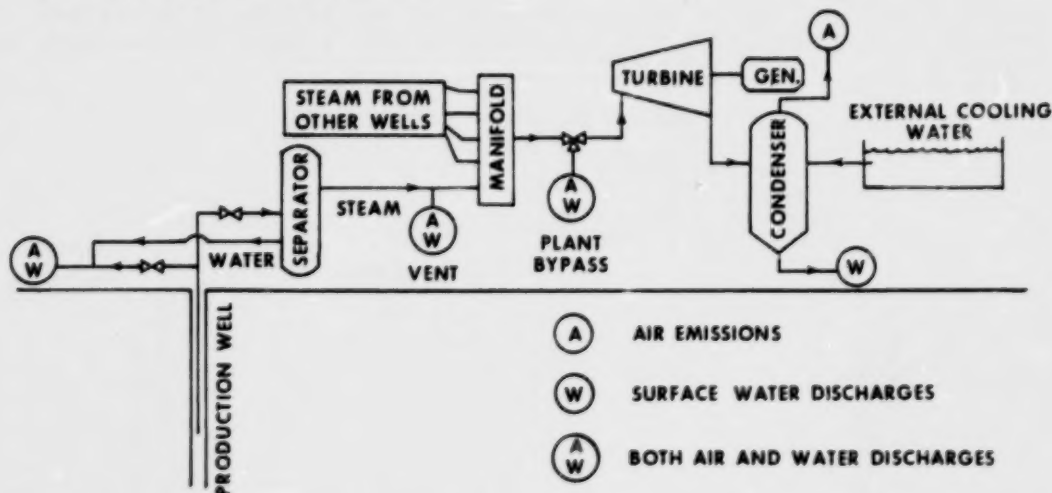


Figure 1. Simplified schematic diagram of open cycle geothermal electric power generation system operating on flashed steam. All spent fluids are discharged to surface water and air.

Another facility might be as shown in Figure 2, which is at the other extreme where the system is closed with potential releases contained and the excess fluids returned to the producing reservoir. The only significant waste loss would be heat to the atmosphere.

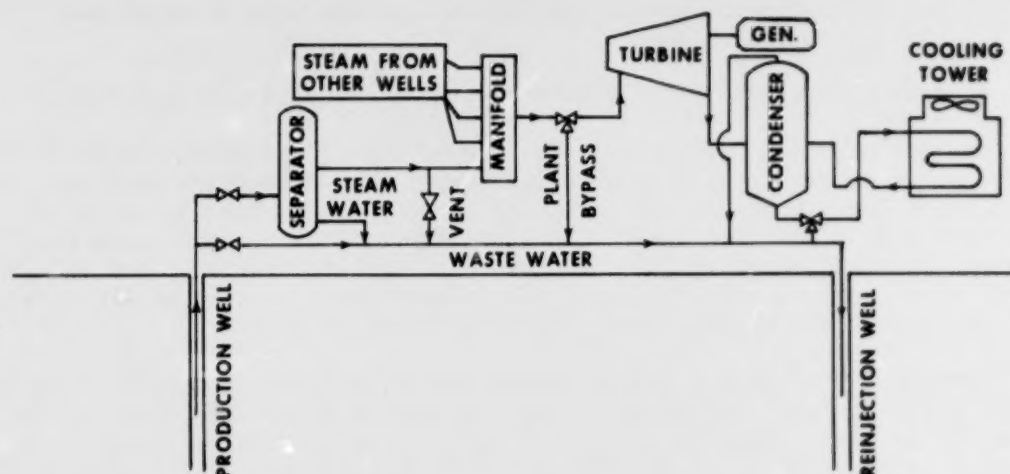


Figure 2. Simplified schematic diagram of closed loop geothermal electric power generation system operating on flashed steam. All spent fluids are injected.

For systems other than power production, such as space heating, operations may be much simpler in principle, to the extent of merely passing the entire fluid flow through heat exchangers and discharging it to surface drainage or reinjection. Such a system might be as shown schematically in Figure 3.

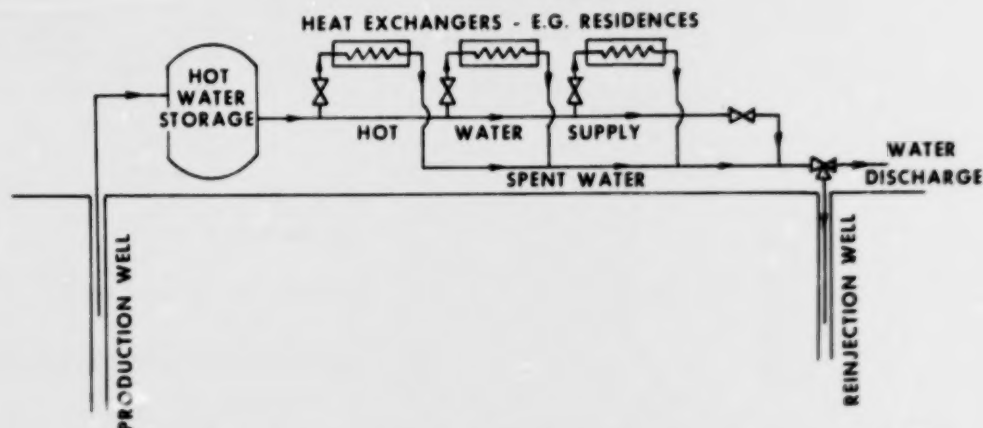


Figure 3. Simplified schematic diagram of non-electric use (space heating) of geothermal energy. Spent fluids either can be injected or discharged to surface waters.

There are many possible variations in and between these schemes. For example, the scheme shown in Figure 3 could be used as part of a power generation system, in which a recycled secondary fluid, heated in the heat exchanger, operates a turbine-generator. The schemes of Figures 1 and 2 can also be made more complex by multi-stage flashing, or simpler by passing the entire well flow through a turbine.

The principal point is that any discharge to the air, to surface drainage, to surface impoundments, or to injection, will be subject to regulatory control of some degree. Also, the restrictions on those discharges are likely to be directly related to the number and concentrations of constituents in the discharged fluids, and to the fluid volume. They will in turn be directly related to the original character of the geothermal fluid.

If geothermal fluids must be treated for constituent removal, solid wastes or more concentrated brines containing most of the fluid chemical constituents will result. These wastes will also be subject to confinement and other controls to prevent surface and ground water contamination. In some cases, brine constituents may be extracted for commercial sale and use.

POLLUTANTS DERIVED FROM GEOTHERMAL FLUIDS

The chemical characteristics of geothermal fluids vary greatly between reservoirs and to a lesser degree even within the same reservoir. The characteristics can also change with time, because of selective withdrawal and recharge factors.

Figure 4 lists some of the more significant chemical constituents of geothermal fluids and graphically depicts their ranges. All of the constituents are natural components of geothermal fluids. The information in Figure 4 has been compiled from an examination of limited data from the literature and unpublished sources.^{9,10,11} Chemical data are now being gathered rather extensively so that the listed ranges will likely expand. Radioactive elements, except for radon gas, which is discussed later, have not been regarded thus far as significant in geothermal fluids.

Figure 4 is biased considerably by data from the Salton Sea (Imperial Valley), where very high constituent concentrations are common (see Ref. 9). In order to add perspective, judgments have been made of ranges within which the majority of concentration measurements will likely occur when all geothermal fluids are considered together. Generally, spent water from most areas is expected to be comparable to or lower than sea water in salinity.

In general, low salinity or low total dissolved solids (TDS) are associated with relatively low concentrations of all constituents and vice versa. As a general rule also, higher temperature waters contain higher constituent concentrations.

Geothermal fluids range rather widely in hydrogen ion concentration, with pH values generally between 2.0 and 8.5. It appears that most fluids are above pH 7.0. Fluids of highest salinity generally have the lowest pH and may be highly corrosive to man-made materials.

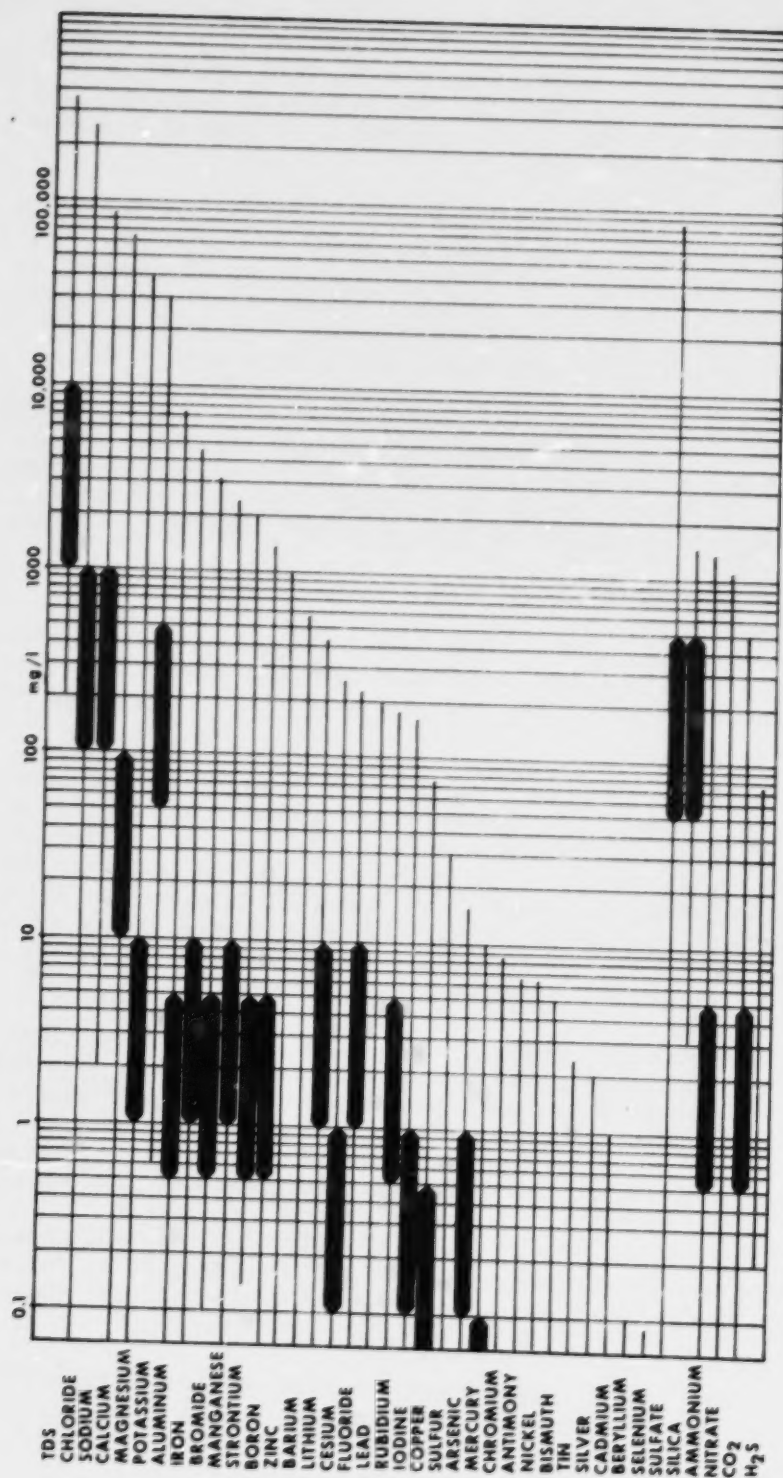


Figure 4. Ranges of chemical constituent concentrations in geothermal fluids - mg/l. Narrow bars show measured ranges. Wide bars show ranges within which the majority of measurements will probably fall. Where no wide bar is shown, data are insufficient to make a judgment. (Ref. 9, 10, 11)

Noncondensable gases, those which do not condense at operating temperatures, are environmentally important constituents of geothermal fluids. They may be free gases or dissolved or entrained in the liquid phase. Hydrogen sulfide has been the component of greatest concern to this time. Noncondensable gases usually comprise between about 0.3% and 5% of flashed steam from geothermal fluids.¹²

Figure 5 depicts the known ranges of noncondensable constituents as percentages of total noncondensable gases.¹¹ Also shown are their probable ranges in parts per million of total gases (including steam) in a steam system. In gas ejector emissions the concentrations can of course be much higher.

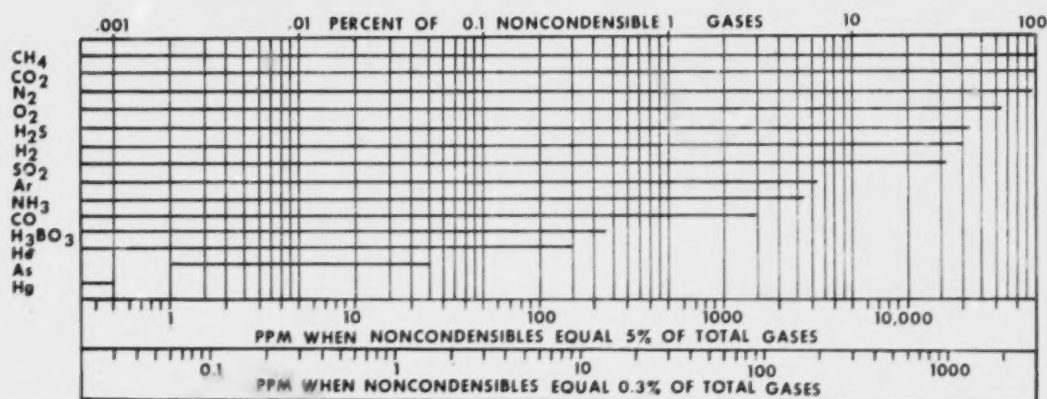


Figure 5. Noncondensable gases in geothermal fluids. Base graph shows individual gases as ranges of percent of total noncondensable gases. Lower scales convert these values to parts per million (ppm) of total (noncondensable plus condensable) gases when noncondensibles equal the specified percentages of total gases.

Radioactive elements are generally found in geothermal fluids in low concentrations. These include uranium and thorium isotopes, radium, and radon. Radon, a radioactive gas and one of the products of radium decay, is the most significant generally recognized radioactive component in geothermal fluids. A survey by EPA¹³ of 136 geothermal manifestations showed a range of 13 to 14,000 pCi/l (picocuries per liter), with a median of about 510 pCi/l. Figure 6 depicts the frequency of occurrence of radon concentrations measured during that survey. The concentrations show considerable variation geographically, with some regions having much higher concentrations than others.

Chemicals, such as acids, bases, and various flocculants and coagulants, may be added to geothermal fluids to minimize scaling and corrosion or to remove certain constituents. Although these chemicals may not in themselves be of great pollution consequence, consideration must be given to them (particularly metal compounds), because they may alter the geothermal liquid

composition toward being more environmentally detrimental. Most such chemicals will likely be acids and/or bases used for pH adjustment.

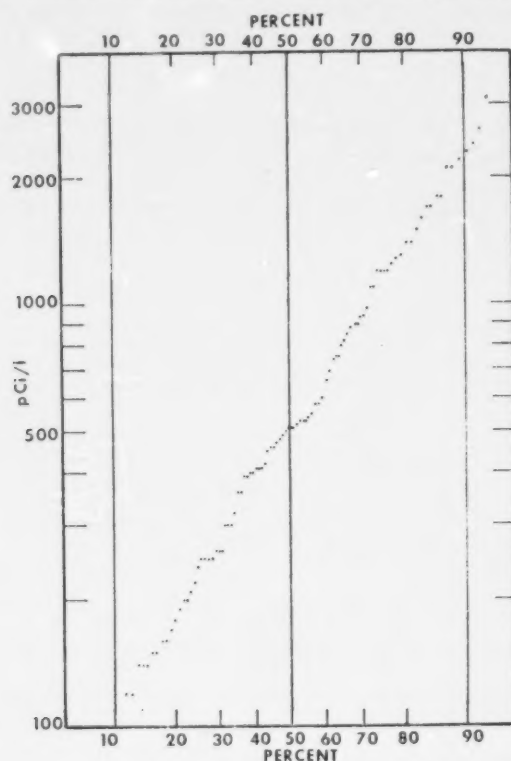


Figure 6. Cumulative frequency distribution for radon-222 in geothermal waters. (Constructed from data in Ref. 13)

Waste heat can be of major significance in geothermal electric power generation because of the relative inefficiencies of low-temperature conversion. Conversion efficiencies are presently less than 20%^{14,15}, so that more than 80% of the available heat is wasted by way of spent brine, condenser cooling water, and condensate. If external once-through cooling water is used, most of the waste heat from cooling will be discharged to surface waters. If cooling towers are used, with the cooling water recycled, and blowdown subsurface-injected, most of the waste heat will be dissipated to the surrounding air. Surface water discharges would be particularly detrimental with large volumes released at temperatures as high as 50°C (120°F).

Chemicals and heat are likely to be much less troublesome contaminants in discharges from non-electric uses of geothermal fluids.¹⁶ One of the principal reasons is that those uses will probably deal with lower temperature waters that are inherently less saline. Another is that non-electric systems probably will demand the use of relatively clean water because they will be in more intimate contact with the ultimate energy user.

Solid wastes may be produced by particle separators, scale removal, and as sludge from water treatment and gas scrubbing. Such wastes will include

the pollutants of the geothermal fluid itself and any treatment chemicals used. If mineral recovery is practiced, the residual will also be solid wastes or bitters. The constituents of geothermal solid wastes have the potential for leachate runoff and infiltration to ground water if not properly handled.

NOISE DERIVED FROM GEOTHERMAL OPERATIONS

In all industrial operations noise is a pollutant that must be accepted to some degree. In geothermal operations noise may be particularly annoying, in part because the areas of operation will be generally remote and otherwise relatively quiet. The most significant potential sources are drilling (particularly with air) and steam flashing and venting.

Table 1 lists examples of noise measurements at The Geysers power generating facility.¹⁷ Noise levels from liquid-dominated sources will likely be similar. In general, noise level decreases from 3 to 6 dBA with every doubling of distance.¹⁶ The expression dBA means "A-weighted" sound level measured in decibels above a reference sound pressure of 0.0002 microbars (20 micropascals). "A-weighting" weights the contributions of sounds of different frequency so that the response of the human ear is simulated.¹⁸

The sound levels listed in Table 1 can be compared to more well-known sources, some of which are:^{18, 19}

• quiet wilderness area	20 - 30 dBA
• quiet suburban residence	48 - 52 dBA
• business office	50 - 60 dBA
• noisy urban area	80 - 90 dBA
• adjacent to freeway	90 dBA
• jet airplane at 100 feet	120 - 130 dBA

As the data in Table 1 indicate, the most intense noise levels in geothermal operations result from steam venting. Mufflers of various designs are in common use, as described in Section VI - Pollution Control Technology.

TABLE 1. SOUND LEVELS FROM VARIOUS NOISE SOURCES AT THE
GEYSERS, dBA, re 0.0002 MBAR OR MICROBAR
(Ref. 17)

Source No.	Noise Source	Sound Level dB(A)	Distance		Comment
			m	ft	
1	Drilling with air	114	8	25	Steam entry of ~81,720 kg (180,000 lb)/hr. No muffler.
2	Same as No. 1	~74	805	2640	Same as No. 1
3	Drilling with air	84	8	25	Steam entry of ~90,800 kg (200,000 lb)/hr. With muffler.
4	Same as No. 3	~65	76	250	Same as No. 3
5	Same as No. 3	<50	805	2640	Same as No. 3
6	Steam well	89/92	14	45	Main valve closed, bleed line exhausting freely.
7	Same as No. 6	73/75	55	180	Same as No. 6
8	Steam well	59/62	14	45	Main valve closed, bleed equipped with silencer, exhausting freely.
9	Steam well	84	27	90	Muffled steam well ex- hausting through silencer, exhausting freely.
10	Steam well	105/110	137	450	Main valve open, unsilenced. Steam plume about 46 m (50 yd) high.
11	Steam well	71/83	914	3000	Main valve open, unsilenced. Steam plume about 46 m (50 yd) high
12	Steam line	92/94	12	40	Directly in front.
13	Same as No. 13	70/75	91	300	15/25 degrees off axis.
14	Testing well (big well)	107	8	25	@122,580 kg (270,000 lb)/hr. With muffler.
15	Same as No. 14	~65	805	2640	Same as No. 14

TABLE 1 (continued)

Source No.	Noise Source	Sound Level dBA	Distance		Comment
			m	ft	
16	Free venting well	120	8	25	@90,800 kg (200,000lb)/hr No muffler.
17	Same as No. 16	~79	805	2640	Same as No. 16
18	0.6 cm (.25 in.) bleed on shut-in well	84	8	25	No muffler.
19	Same as No. 18	~65	76	250	Same as No. 18
20	Same as No. 18	<50	805	2640	Same as No. 18
21	Steam line vents from main line mufflers of 2 units	84	244	800	15/25 degrees off axis
22	Power plant	96	15	50	454,000 kg (1 million lb)/hr.
23	Same as No. 22	~61	805	2640	Same as No. 22
24	Steam jet gas ejector	91	1.5	5	Microphone height 1.5 m (5 ft). Unit load unknown.
25	Steam jet gas ejector	88	3	10	Microphone height 1.5 m (5 ft). Unit load 41 MW.
26	Same as No. 25	86	6	20	Same as No. 25
27	Cooling tower for 2 units	81	3	10	Microphone height 1.5 m (5 ft).
28	Cooling tower for 2 units	84	3	10	Microphone height 1.5 m (5 ft).
29	Same as No. 28	80	12	40	Same as No. 28
30	Same as No. 28	72	43	140	Same as No. 28
31	Outside turbine generator building	72	8	25	One unit - 44 MW; second unit - 54 MW

V. ENVIRONMENTAL EFFECTS OF KNOWN POLLUTANTS

GENERAL

Under current laws, discharge permit limitations based upon guidelines and performance standards are the principal and preferred regulatory methods, unless such limitations still allow receiving media standards to be violated. In such cases, the permit limitations will be derived from effects-based media standards. They also may prevail where effluent guidelines and emission standards have yet to be developed; such is the case with the geothermal industry. The current receiving media standards most applicable to the geothermal industry are those for water quality. Table 2 lists the geothermal constituents and those regulated by existing water quality standards for those States with significant geothermal potential.

As indicated by Table 2, geothermal fluids may contain constituents not currently controlled by media standards. Since geothermal industry Effluent Guidelines and New Source Performance Standards have not been developed, and toxic substance limitations have not been established, it is appropriate to discuss the environmental effects of geothermal fluid constituents as the first consideration in the establishment of an appropriate control basis.

Environmental effects are discussed herein only in very general terms. No attempt is made to detail the literature that may be available on toxicity, for example. It is recognized that much greater detail for mixtures unique to geothermal fluids may be justified as geothermal development progresses. It is also recognized that such detail will require complex analyses, both theoretical and empirical. Although a considerable number of elemental chemical analyses are available, the effects of mixtures of these elements are largely unknown. Often, it is the mixture of compounds that determines the level of environmental effects. The effects may be synergistic, antagonistic, or independent.

WATER POLLUTANTS

The following discussion of environmental effects is divided into areas of water use, as has been characteristic of water quality standards development. The potential water pollutants and their probable concentration ranges in geothermal waste fluids were shown in Figure 4. Some geothermal reservoirs may produce waters of sufficient quality for many uses, including human consumption; however, this is not expected to be generally true.

TABLE 2. POLLUTANTS LIMITED BY WATER QUALITY STANDARDS
IN STATES WITH GEOTHERMAL POTENTIAL

	Alaska	Arizona	California	Colorado	Hawaii	Idaho	Louisiana	Montana	Nevada	New Mexico	Oregon	Texas	Utah	Washington	Wyoming
Total dissolved solids	d				d		d		d	d	d	d	p		
Chloride							d		s	d	d	d			
Sodium															
Calcium															
Magnesium															
Potassium															
Aluminum								d			d		p		
Iron															
Bromide											d		p		
Manganese															
Strontium									d		d				
Boron		d						d			d	s	p		
Zinc		d									d	s	p		
Barium		d	s												
Lithium															
Cesium											d		p		
Fluoride								d			d	s	p		
Lead		d	s												
Rubidium															
Iodine		d						d			d	s	p		
Copper															
Sulfur		d	s					d			d	s	p		
Arsenic		d	s					d				s			
Mercury		d	s								d	s	p		
Chromium		d	s												
Antimony												s			
Nickel															
Bismuth															
Tin												s	p		
Silver		d	s					d			d	s	p		
Cadmium		d	s												
Beryllium			d	s								s	p		
Selenium							d			d		d	p		
Sulfate															
Silica															
Ammonium				s							s			p	
Nitrate (+ nitrite)		s	d	d	s	s	s	s	s	s	s	s	s	s	s
pH (range)		d	s	d	s	s	s		d	s		s	s	s	s
Radioactivity		d	s	d	s	s	s		s		s	s		s	d
Total dissolved gas		d	f		f	f	s	s	s	f	s		s	s	f
Toxic materials		d	d	d	d	d	d		d	d	d	d	d	d	d
Temperature		d	d	d	d	d	d		d	d	d	s	s	s	s
Dissolved oxygen (min.)		s	d	d	a	s	s		d	d	d				
Phosphorus											d	d			
Conductivity															

d = criteria for designated waters; s = criteria applied statewide;
p = criteria conform with USPHS Drinking Water Standards, 1976;
f = free from toxic materials.

Human Use

Of greatest concern is the protection of public drinking water supplies. Spent geothermal liquids, in the massive amounts expected to be discharged, could have very serious effects if allowed to enter drinking water sources. The effects of injection to ground water supplies could be disastrous, because such contamination might well be impossible to correct.

Table 3 provides some general toxicological information on compounds (mainly inorganic) containing each of the significant geothermal fluid constituents. The toxicological information is related to direct undiluted oral ingestion.^{20,21} No attempt is made to give toxic amounts because they are highly variable, depending frequently upon associated ions, the health of the individual, and the time over which the ingestion takes place.

Table 3 also includes the permissible or recommended maximum concentrations of constituents in public water supplies.^{22,23} Comparison of this list with toxicity levels indicates those constituents in geothermal fluids that may have pollutional significance, but are not mentioned in drinking water regulations. These are bromide, lithium, iodide, antimony, and bismuth. Although no drinking water standards have been established for these constituents, it would be fair to assume that, if such are developed, they will be something less than 1 mg/l for each. Sulfides, nickel, and potassium from geothermal fluids may have potential health effects, but no limits can be suggested.

Each of the constituents in Table 3, for which an acute and/or chronic toxicity level of 1 or higher is shown, should be viewed as subject to discharge control in geothermal operations. Control methods and their effectiveness are discussed in the next chapter.

Aquatic Life

The EPA has recently published (1977) "Quality Criteria for Water,"²⁴ in which many of the constituents found in geothermal fluids are not considered. Table 4 has been prepared largely from the information contained in that document, supplemented by others,^{25,26} in which much of the emphasis is on the protection of aquatic life from acute and chronic toxicity. Data in Table 3 on humans give cause to suspect that the same constituents may have effects upon aquatic life. Comparison of Table 4 with Table 3 shows then that there are many geothermal fluid constituents that may have significant effects upon aquatic life, but have not yet been included in criteria development. These constituents include:

- | | |
|-------------|------------|
| • Aluminum | • Fluorine |
| • Bromine | • Rubidium |
| • Strontium | • Antimony |
| • Lithium | • Nickel |
| • Cesium | • Bismuth |

TABLE 3. EFFECTS ON HUMANS OF ORAL INGESTION OF COMPOUNDS

	Acute Toxicity of Compounds	Chronic Toxicity of Compounds	Digestive	Respiratory	Systemic Effects		Skeletal	Muscular	Drinking Water Standard (mg/l)
					Vascular	Nervous			
TDS	0	0	X						500
Cl	0	0							250
Na	0	0			X				
Ca	0	0							
Mg	1	0		X		X			
K	0-2	0	X	X	X				
Al	0	0							
Fe	0	0							0.3
Br	2	0				X			
Mn	0	0							0.05
Sr	0	0							
B	2	2	X			X			1.0
Zn	1	0	X						5.0
Ba	2	1	X		X	X		X	1.0**
Li	2	1				X			
Cs	0	0							
F	3	3	X			X	X		1.4-2.4
Pb	3	3	X			X		X	0.05**
Rb	0	0							
I	2	2		X					
Cu	2	1	X			X			1.0
S	0-2	0-2	X						
As	3	3	X		X				0.05**
Hg	3	3	X			X		X	0.002**
Cr	3	3	X		X	X			0.05**
Sb	3	3	X		X	X		X	
Ni	1	0	X						
Bi	2	1	X						
Sn	0	0							
Ag	0	0							0.05**
Cd	3	3	X						0.01**
Be	0	0							
Se	2	2	X						0.01**
SO ₄	0	0	X						250
SiO ₂	0	0							
NH ₄	0-1	0-1	X						0.5 as N
NO ₃	2	2	X		X				10 as N**

Toxicity Ratings: 0 - usually not harmful or harmful only with overwhelming dosage; 1 - causes reversible changes which usually disappear after end of exposure; 2 - causes reversible or irreversible changes not severe enough to cause death; 3 - may cause permanent injury or death after ingestion of small quantities.

* Sodium intake must be limited for some cardiac patients, with a generally accepted limit of 20 mg/l in drinking water.

** Standards established by 40 CFR 142; all others are USPHS-recommended (1962)²²

TABLE 4. AQUATIC LIFE CRITERIA FOR CONSTITUENTS IN GEOTHERMAL FLUID - FROM "QUALITY CRITERIA FOR WATER" (1977)24

Constituent	Criteria for Fresh water	Criteria for Marine water	Remarks
Ammonia (un-ionized)	0.02 mg/l		Toxicity pH dependent
Arsenic			
Barium			Daphnia impaired by 4.3 mg/l
Beryllium	0.11 mg/l - soft water 1.1 mg/l - hard water		Toxicity level >50 mg/l Toxicity hardness - dependent
Boron			
Cadmium	.004-.0004 mg/l - soft water .012-.0012 mg/l - hard water	0.005 mg/l	Toxic to minnows at 19,000 mg/l Toxic at <0.5 mg/l all tests
Chromium	0.1 mg/l		Toxicity varies with pH and oxidation state
Copper	0.1 96 hr LC50	0.1 96 hr LC50	Toxicity alkalinity - dependent
Iron	1.0 mg/l		Toxicity variable
Lead	0.01 96 hr LC50 (sol. lead)		Salmonids most sensitive fish
Manganese		0.1 mg/l	Not a problem in fresh water
Mercury	0.0005 mg/l	0.0001 mg/l	High bio-accumulation and thus affects human food
Nitrates			Toxicity to fish >900 mg/l
Phosphorus		0.0001 mg/l P	Eutrophication factor
Selenium	0.01 96 hr LC50	0.01 96 hr LC50	Toxic at >2.5 mg/l
Silver	0.01 96 hr LC50	0.01 96 hr LC50	Toxicity dependent on compound
H ₂ S	0.0002 mg/l	0.0002 mg/l	Toxic at very low levels
Zinc	0.01 96 hr LC50		Toxicity dependent on temperature, DO, hardness
Total Dissolved Solids (TDS)			Osmotic effects - variable

One of the reasons that the above have not been included is that most have not normally been considered significant components of waste waters or of natural waters. This of course is not always true; for example, fluorides are significant components of natural waters in several areas.

Caution should also be exercised in the use of the data in Table 4, where no criteria are shown; e.g., arsenic, barium, and boron. These may exist in geothermal waters in much higher concentrations than regulatory agencies have had to deal with in other waters.

Criteria cannot be reasonably suggested here for those constituents that have not been covered in criteria development documents. As noted previously, such development requires complex analyses.

Waste heat may have particularly significant effects upon aquatic life. Excess heat, as expressed by artificial temperature rise or temperature fluctuations, can disturb aquatic communities to the extent of complete elimination and replacement by different species. An excellent summary of temperature-induced aquatic effects is presented in reference 24. Most water quality standards limit artificially induced stream temperature rise outside a mixing zone to 5°F (2.6°C) or less. Generally, the standards also include a maximum stream temperature tailored to the preferred temperature of native fish species.

The pH of surface waters has been related to productivity, with the most productive waters between pH 6.5 and 8.5. Not only may acids and alkalis be toxic in themselves, but pH increases or decreases may increase the toxicity of various constituents, e.g. ammonia.

Agricultural Use

Two uses are commonly included in considering pollution effects and water quality criteria for agriculture. These are livestock watering and irrigation. Criteria developed in "Quality Criteria for Water"¹⁹ are listed in Table 5, for those constituents that are found in geothermal waters. Again it must be emphasized that those criteria do not discuss many of the geothermal constituents that may be detrimental to agricultural use.

Criteria development for agricultural water uses has obviously not received the attention that it has for aquatic life and drinking water. This becomes obvious in a comparison of the numbers of criteria presented in Tables 4 and 5. Here again, such development would involve complex evaluations. Thus, additional criteria are not suggested herein.

Industrial Water Supply

As a general rule, industrial water supplies are adversely affected by excessive total dissolved solids concentrations, although there is wide variability in the quality of water used among various industries (see Table 6).²⁵ Geothermal fluids from many reservoirs could potentially contribute very large quantities of dissolved solids, which could be removed from industrial water supplies, but the cost in some cases would be prohibitive.

TABLE 5. AGRICULTURAL USE CRITERIA FOR CONSTITUENTS IN GEOTHERMAL FLUIDS FROM "QUALITY CRITERIA FOR WATER" (1977)²⁴

Livestock Watering	Crop Irrigation	Remarks
Ammonia		No criteria suggested.
Arsenic	0.1 mg/l	Toxicity to some crops at 0.5 mg/l; no livestock criteria suggested.
Barium		No criteria suggested.
Beryllium	.001 to .500 mg/l	Crop toxicity acidity dependent; no livestock criteria suggested.
Boron	0.75 mg/l	Toxic to sensitive plants, e.g. citrus at <1 mg/l; no livestock criteria suggested.
Cadmium		Reduced crop yields at 1 mg/l; crop accumulation related to zinc concentrations; no livestock criteria suggested.
Chromium		No criteria suggested.
Copper		Toxicity for plants begins at 0.1 mg/l; no livestock criteria suggested.
Iron		No criteria suggested.
Lead		Toxic to plants at <30 mg/l; no criteria suggested.
Manganese	0.2 mg/l suggested for acidiphilic crops	Toxicity to plants increases with decreasing pH; no livestock criteria suggested.
Mercury		Bio-accumulation but no criteria suggested.
Nitrates		No criteria suggested; nutrient for crops.
Phosphorus		No criteria suggested; nutrient for crops.
Selenium		No criteria suggested.
Silver		No criteria suggested.
H ₂ S		No criteria suggested.
Zinc		Toxic to some crops at 0.4 to 25 mg/l may cause iron deficiency in plants; no livestock criteria suggested
Total Dissolved Solid (TDS)	5,000-15,000 mg/l suggested	Osmotic effects in plants; variable harm to both plants and animals.
Sodium		Toxic to certain plants; ratio to other cations important; no criteria given.

Some industrial processes (e.g. food and beverages) may require as high or higher quality than drinking water, in order to maintain consistency of product quality.

TABLE 6. TOTAL DISSOLVED SOLIDS CONCENTRATIONS OF SURFACE WATERS THAT HAVE BEEN USED AS SOURCES FOR INDUSTRIAL WATER SUPPLIES²⁵

Industry/Use	Maximum Concentration (mg/l)
Textile	150
Pulp and Paper	1,080
Chemical	2,500
Petroleum	3,500
Primary Metals	1,500
Copper Mining	2,100
Boiler Make-up	35,000

AIR POLLUTANTS

The potential air pollutants and their probable ranges in geothermal steam and air emissions were shown in Figure 5. Only one of them, sulfur dioxide, is now subjected to regulation from all stationary sources under the Federal Clean Air Act. Mercury vapor emissions are regulated by the Hazardous Air Pollutant section of the Clean Air Act only for mercury ore processing facilities, mercury cell chlor-alkali plants, and sewage sludge incineration. Hydrogen sulfide emissions are regulated by some states, but not by Federal regulations. Some of the noncondensable gases in geothermal fluids are ordinary, relatively innocuous components of the atmosphere and control is unnecessary.

Effects on Humans

The greatest concern about any of the noncondensable gases is their effect on human health.

Table 7 shows the general inhalation effects of each of the significant gases contained in geothermal fluids.²⁰ The listed toxicity effects are derived from inhalation of high dosages in confined spaces. However, the relative toxicities and the existence of significant concentrations in geothermal air emissions may indicate which constituents are more likely to require control.

Carbon dioxide, nitrogen, and helium are relatively harmless, but may cause asphyxiation in massive doses. Hydrogen sulfide, sulfur dioxide,

TABLE 7. EFFECTS ON HUMANS OF INHALATION OF GASES OR VAPORS²⁰

	Acute Toxicity	Chronic Toxicity	Systemic Effects				Fatal Dose* (ppm)	Odor (ppm)	MAC** (ppm)
			Respiratory	Vascular	Nervous	Muscular			
CH ₄	1	1	x	x					
CO ₂	0	0							5000
N ₂	0	0							
O ₂	0	0							
H ₂ S	3	3	x				>1000	>0.03	10
H ₂	0	0							
SO ₂	3	2	x				400-500	3	5
Ar	1	0	x						
NH ₃	3	u	x						
CO	3	1	x	x			4000		50
H ₃ BO ₃	2	2	x						
He	1	0	x						
As	3	3	x		x				
Hg	2	3	x		x	x			

Toxicity Ratings: 0 - usually not harmful or only harmful with overwhelming doses.
 1 - causes reversible changes which usually disappear after end of exposure; simple asphyxiants.
 2 - causes reversible or irreversible changes not severe enough to cause death.
 3 - may cause permanent injury or death after ingestion of small quantities.

*Fatal dose concentrations in air which cause death with less than one hour exposure.

**Maximum acceptable concentration - concentration in air which can be withstood continuously without noticeable harm.

ammonia, carbon monoxide, arsenic, and mercury may cause serious harm upon inhalation of relatively small amounts.

Hydrogen sulfide appears to be universally present in geothermal fluids in quantities sufficient to be of environmental concern. That concern is increased by the odor nuisance resulting from very small concentrations of hydrogen sulfide. Even though in sufficient concentrations it is very toxic, the odor nuisance at low non-toxic levels creates public antagonism. Its toxicity effects may be significant in the immediate vicinity of the emission.

The information on hydrogen sulfide in Table 8 is taken from a literature review by the U. S. Public Health Service.²⁷

TABLE 8. HYDROGEN SULFIDE EFFECTS ON HUMANS²⁷

Concentrations (ppm)	Effects
.0007 - .030	odor threshold
0.33	distinct odor; can cause nausea, headaches
2.7 - 5.3	odor offensive and moderately intense
20 - 33	odor strong but not intolerable
100	can cause loss of sense of smell in few minutes
210	smell not as pungent, probably due to olfactory paralysis
667	can cause death quickly due to respiratory paralysis
750	virtually no odor sensation; death can occur rapidly, upon very short exposure

Hydrogen sulfide in the facility work environment (e.g. power plant) is likely to be of greater health significance than in relatively distant areas. The Occupational Safety and Health Administration regulations (29 CFR 1910.1000) list an acceptable ceiling concentration, without respiratory protection, of 20 ppm, with a maximum peak of 50 ppm for a 10-minute exposure. The American Conference of Governmental Industrial Hygienists²⁸ currently recommends a time-weighted average limit over the work day or week of 10 ppm, with a short-term (15 minute) exposure limit of 15 ppm. Conformance with these criteria may obviate human health concerns outside the work environment.

Effects on Plants and Crops

Only hydrogen sulfide, sulfur dioxide and boron (boric acid) in geothermal gases are currently recognized as potentially damaging to crops. Both

hydrogen sulfide and sulfur dioxide are converted to acid of sulfates in the environment, which can be damaging to plants and crops when in high enough concentrations. Normally, such concentrations will not be reached through geothermal emissions. Boron may also wash out of the air and damage plants, particularly citrus crops.

NOISE POLLUTION

Geothermal development may cause noise pollution that is intolerable at short distances without personal protection, particularly during (1) drilling, particularly with compressed air, and (2) high volume steam losses, including atmospheric flashing.

Noise pollution, unlike water and air pollution, is contaminating only while it is occurring and only in the immediate vicinity of the source. Thus, its most serious consequences occur near the source and are directly related to the length of exposure. The effects are functions of intensity and exposure time. In geothermal development, both can be large.

The effects upon humans of geothermal development noise can take many forms and can be physiological or psychological, or both. Effects include hearing loss, interference with communication, sleep disturbance, and stress reactions that can have long term health implications.

This document does not attempt to precisely relate noise effects to noise levels, with respect to humans or other animal life. These relationships have been documented by EPA.^{18,19} Occupational Safety and Health Administration requirements for the workplace specify that no worker be subjected to 115 dBA for more than 15 minutes or to 90 dBA for more than eight hours.

The noise limitations imposed upon geothermal operations on Federal lands specify a maximum level of 65 dBA at the lease boundary or a distance of one-half mile from the source, whichever is greater.⁹

LAND-DISPOSED WASTES

The effects of pollution from land-disposed wastes should be similar to those described previously under Water Pollution, since contamination would be derived from leachate runoff and/or percolation to ground water.

RADIATION

Radiation, from radioactive materials, is a known carcinogen. At present there is no level of exposure below which it is accepted that no biological damage occurs. Any radiation exposures resulting from geothermal operations would be caused by a redistribution of naturally occurring radioactive materials. The environmental effects could be due to external and internal irradiation. The transfer of radionuclides to man is commonly by ingestion of food and water and by inhalation.

VI. POLLUTION CONTROL TECHNOLOGY

This section describes pollution control technologies that are or may be applicable to discharges and emissions from geothermal energy conversion systems. It also examines the costs of those technologies to the extent that they can be determined.

As stated earlier, the EPA pollution control regulatory approach to geothermal energy development is directed primarily toward the eventual establishment of Effluent Guidelines and New Source Performance Standards. Such regulations are based upon the best demonstrated economically achievable control technology in the industrial category to which they are applied.

Most of the technologies described herein either have not been applied to geothermal operations or have been applied on a very limited scale. Thus, in general, their applicability and their costs must be considered preliminary judgments based mainly upon the use of those technologies in other industrial sectors. Most of the following technology and cost information has been extracted from a preliminary comprehensive study done for EPA by TRW Inc.²⁹

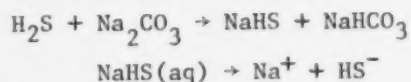
AIR POLLUTION

Technologies to control air pollution from geothermal operations are directed primarily at incoming steam, condenser vent emissions, and cooling tower emissions. In all of these, hydrogen sulfide (H₂S) is the pollutant currently of greatest concern. Each of the described technologies removes hydrogen sulfide.

Stretford Process

Process Description

A simplified flow diagram of the Stretford process is shown in Figure 7. The process produces elemental sulfur and is applicable to those geothermal energy conversion processes condensing steam.³⁰ It scrubs noncondensable gases from the condenser ejector with an aqueous solution containing sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA). An alkaline solution of sodium carbonate and bicarbonate is produced with the carbon dioxide present in the scrubbed gas stream. The gas stream is scrubbed countercurrently with the alkaline solution in the absorber, and hydrosulfide (HS⁻) is formed:



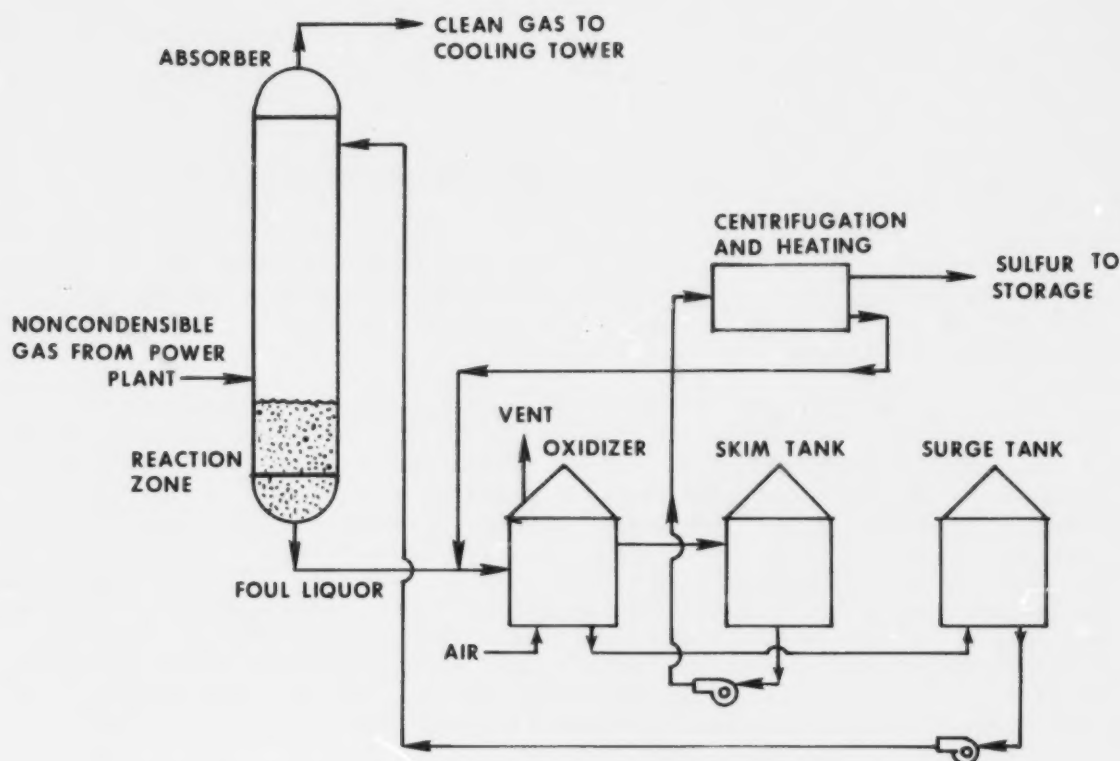
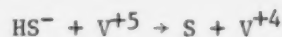
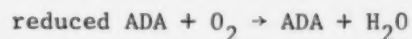
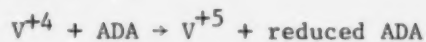


Figure 7. Flow Diagram of A Stretford Process

The hydrosulfide is oxidized by 5-valent state vanadate to form elemental sulfur and 4-valent state vanadate:



The above reaction is hindered by pH over 9.5, thus the pH is controlled in the optimum range of 8.5 to 9.5 by adding sodium hydroxide. Scrubbing solution is regenerated by blowing air into the oxidizer, and the reduced vanadate is restored to the 5-valent state through a mechanism involving oxygen transfer by the ADA:



Air blown into the oxidizer brings the suspended elemental sulfur to the surface. The sulfur froth is removed to the skim tank and is either filtered, centrifuged, or washed and melted to produce high quality sulfur. The Stretford process is over 99 percent efficient, thus removing essentially all of the hydrogen sulfide from the condenser off gases. The overall reaction is:



A surface condenser rather than a direct contact condenser must be used with the Stretford process, to eliminate direct contact of the cooling water with the condensate. Thus, the amount of water (condensate only - not cooling water) available for hydrogen sulfide to dissolve in is significantly reduced. However, with a surface condenser approximately 10 to 20 percent of the hydrogen sulfide remains in solution with the condensate. The hydrogen sulfide dissolved in the condensate is stripped out of solution in the cooling tower and emitted to the atmosphere. Therefore, if a Stretford process is applied to a geothermal energy conversion system designed with a surface condenser, 80 to 90 percent of the hydrogen sulfide existing in the turbine discharge can be removed. The Stretford process will effectively control hydrogen sulfide emissions without any direct detrimental influence on the power cycle. However, the conventional geothermal energy conversion system requires redesigning to include the surface condenser.

Costs

Stretford process cost estimates are based on the process currently being designed for installation on one unit at the Pacific Gas and Electric Geysers facility in 1978. Capital costs include the differential investment required for a surface condenser in lieu of a direct contact condenser. Capital costs for desired cases, where hydrogen sulfide concentration or steam flow rates differ from those given for The Geysers base case, can be computed utilizing the following formulas:³¹

$$IA = IB \left(\frac{SA}{SB} \right)^{0.4} \quad \text{for: } 0.5 < SA < 5 \text{ metric tons of sulfur per day}$$

$$IA = IB \left(\frac{SA}{SB} \right)^{0.5} \quad \text{for: } 5 < SA < 250 \text{ metric tons of sulfur per day}$$

SA = metric tons of sulfur produced per day in the desired case

SB = metric tons of sulfur produced per day by the base case (The Geysers unit) using the Stretford process.

I = Capital investment for the desired or base (A or B) Stretford process.

The following assumptions were used to estimate the annual capital and operating/maintenance costs for a Stretford unit:

- Amortization period: 15 years³²
- Maintenance materials: 2 percent of the installed capital cost³¹
- Maintenance labor: 10 percent downtime, requiring a two man maintenance crew, earning approximately \$30 per hour.
- Electrical power usage: 66 operating BHP per metric ton of sulfur produced per day³¹
- Chemical cost: \$35 per metric ton of sulfur produced per day³¹

- Sulfur credit: \$20 per metric ton
- Construction site: The Geysers

Costs, in mills/KWH, for power generation capacities ranging from 12.95 MW to 117.5 MW and a hydrogen sulfide concentration of 220 ppm are presented in Figure 8. A greater or lesser quantity of steam produced from other geothermal resources may be required to produce the same amount of electrical energy generated at The Geysers. Since the cost of a Stretford process is a function of the sulfur mass flow rate, costs will vary from those presented in Figure 8 for other geothermal applications.

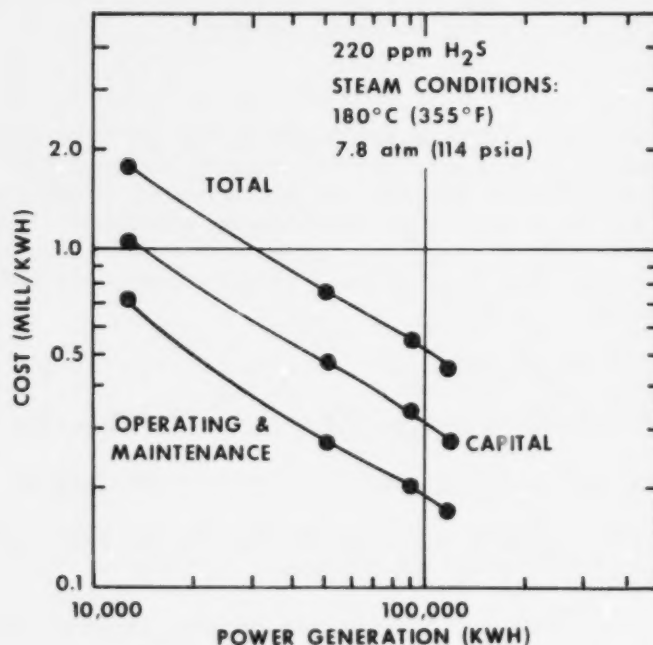


Figure 8. Stretford annual cost vs. power generation

Iron Catalyst Process

Process Description

The iron catalyst (or Ferrifloc) system has been developed by Pacific Gas and Electric Company and is presently in use for hydrogen sulfide control at The Geysers geothermal field.³³ This system is applicable to geothermal conversion systems condensing steam and equipped with direct contact condensers. A simplified flow diagram of this process is shown in Figure 9.

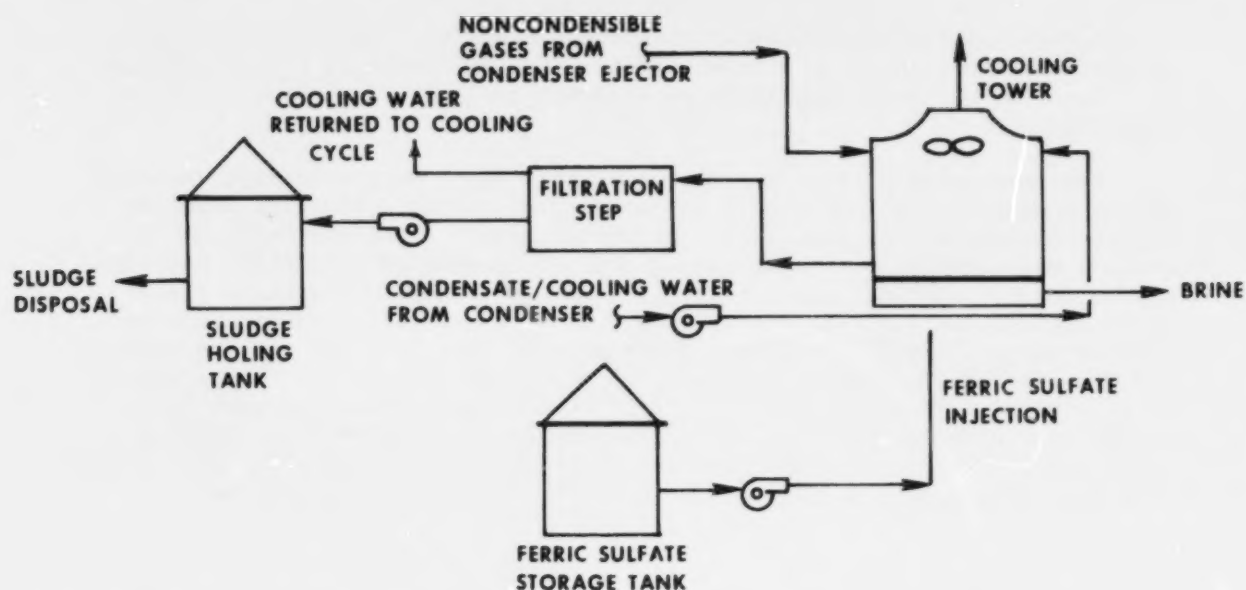
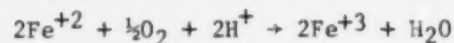
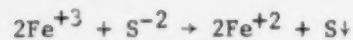
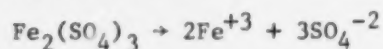
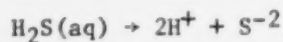


Figure 9. Iron catalyst hydrogen sulfide removal process

Ferric sulfate, in solution, is added to the cooling water, thus oxidizing the hydrogen sulfide contained in the aqueous phase. The noncondensable condenser ejector gases are ducted to the cooling tower and hydrogen sulfide is scrubbed by the falling water containing the ferric sulfate catalyst. Operational experience at The Geysers indicates that practically all of the hydrogen sulfide dissolved in the cooling water/condensate stream is stripped out into the air stream as it passes through the cooling tower. Therefore, any process controlling hydrogen sulfide emissions by treatment of the cooling water must be applied to the cooling water upstream of the cooling tower. The addition of ferric sulfate makes ferric ions available to react with the dissolved hydrogen sulfide, thus forming elemental sulfur, water, and ferrous ions. The reaction mechanism is given below:



The ferrous ions react with the oxygen encountered in the cooling tower to regenerate the ferric ions. Thus, the regenerated ferric ions are available and the hydrogen sulfide reaction repeats continuously to form elemental sulfur. The elemental sulfur produced by this process is removed from the cooling water by filtration. The original design for this system included the use of sand filters; however, significant plugging and maintenance problems have been encountered at The Geysers facilities. To resolve these difficulties,

alternative filtration systems are being investigated. The filtration step generates large quantities of toxic sludge that may cause disposal problems. An industrial waste disposal site or appropriate landfill disposal site is required.

The iron catalyst system results in significant corrosion rate increases in the condenser, cooling tower, and associated piping. Plugging problems will be similarly increased in all of the equipment in contact with the cooling water/condensate. The direct contact condensers presently operating at The Geysers with an iron catalyst system are clad with stainless steel. It is anticipated that the accelerated corrosion rate will reduce condenser life to seven years.³⁴ Insoluble salts carried over into the cooling tower blowdown may cause plugging problems in the injection well, if the blowdown is reinjected. The iron catalyst system is the only present control technology in use to control hydrogen sulfide emissions from both the cooling tower and condenser ejector. The overall hydrogen sulfide removal efficiency from the power cycle for the iron catalyst system is 90 to 92 percent.

Costs

The iron catalyst system is currently in operation at the Pacific Gas and Electric Geysers facility on three units. The installed capital cost of The Geysers unit 11 iron catalyst system³⁰ was used as a basis for the cost estimates presented. It includes a differential investment for sludge thickeners in lieu of sand filters.³⁵

Capital costs for iron catalyst systems with steam flow rates differing from those at The Geysers can be calculated with the following formula:

$$IA = IB \left(\frac{STA}{STB} \right)^{0.6}$$

STA = Steam flow rate of desired iron catalyst system

STB = Steam flow rate of base case (907,000 kg/hr)

I = Capital investment for the desired or base (A or B) iron catalyst system.

The cost of the iron catalyst system is a function of the cooling water/condensate flow rate; which is directly proportional to the steam flow rate. Therefore, the steam flow rate is an acceptable variable in the cost equation. Capital costs were assumed not to be affected by variations in hydrogen sulfide concentration. Operation and maintenance costs for electrical power and chemical usage are assumed to be linearly dependent upon: steam flow rate (with constant hydrogen sulfide concentration) and hydrogen sulfide concentration (with constant steam flow rate). Operation and maintenance costs are difficult to estimate because of the operational problems encountered at The Geysers.³⁶

The following assumptions were used for the iron catalyst annual capital and operation/maintenance cost estimates:

- Amortization period: 15 years
- Maintenance materials: 1 percent of the installed capital cost
- Maintenance labor: 10 percent down time, requiring a two man crew, earning approximately \$30 per hour
- Electrical power usage: 68 KW per hour³⁵
- Ferric sulfate usage: 0.5 kg ferric sulfate per kg of hydrogen sulfide, with a loss factor of 20 percent³⁰
- Ferric sulfate cost: \$0.05 per lb³⁵ (0.11/kg)
- Removal efficiency: 90 to 92 percent
- Construction site: The Geysers

Costs, in mills per KWH, for power generation capacities ranging from 12.1 MW to 110 MW and a hydrogen sulfide concentration of 220 ppm are presented in Figure 10. Costs are based specifically on the operating conditions for The Geysers unit 11 power plant and should not be applied to geothermal energy conversion systems in general. At constant flow rates, costs increase with increasing H₂S concentrations.

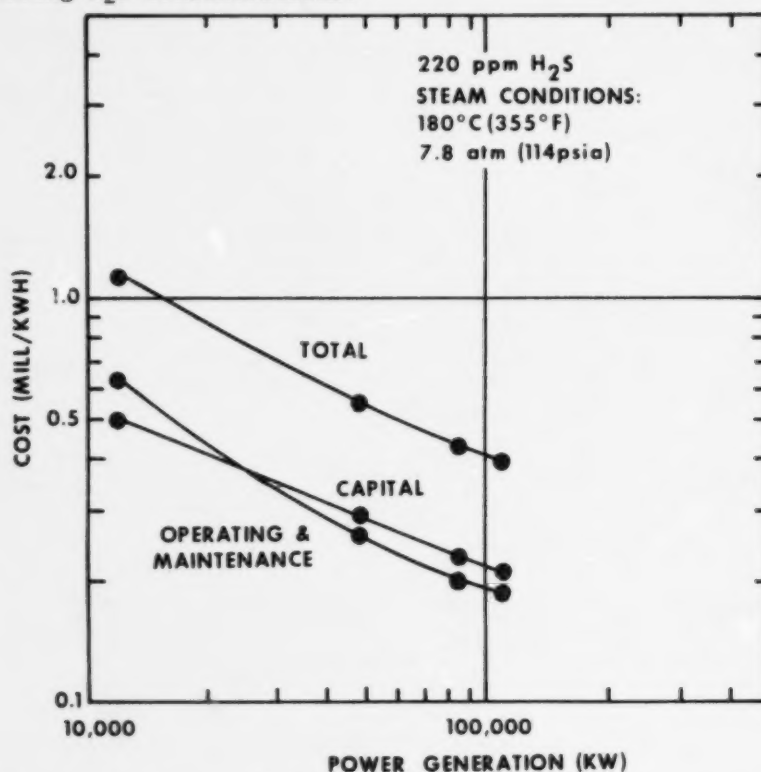


Figure 10. Iron catalyst annual cost vs. power generation

EIC Process

Process Description

The EIC process removes hydrogen sulfide from raw geothermal steam by scrubbing it with an aqueous solution of copper sulfate.³⁷ The hydrogen sulfide and copper sulfate react in a scrubber, forming a copper sulfide precipitate. The process is potentially valuable because it can remove hydrogen sulfide from the plant input steam even while the plant may be shut down. Another benefit of an upstream scrubbing process is the reduction of corrosive effects of H_2S on the turbine and condensing/cooling cycle equipment. This enables the use of standard materials of construction for the power plant equipment and piping. The EIC process removes hydrogen sulfide without significant degradation of steam quality (temperature and pressure). A simplified flow diagram of the EIC process, with regeneration by roasting, is shown in Figure 11. Figure 12 shows the process with regeneration by leaching.

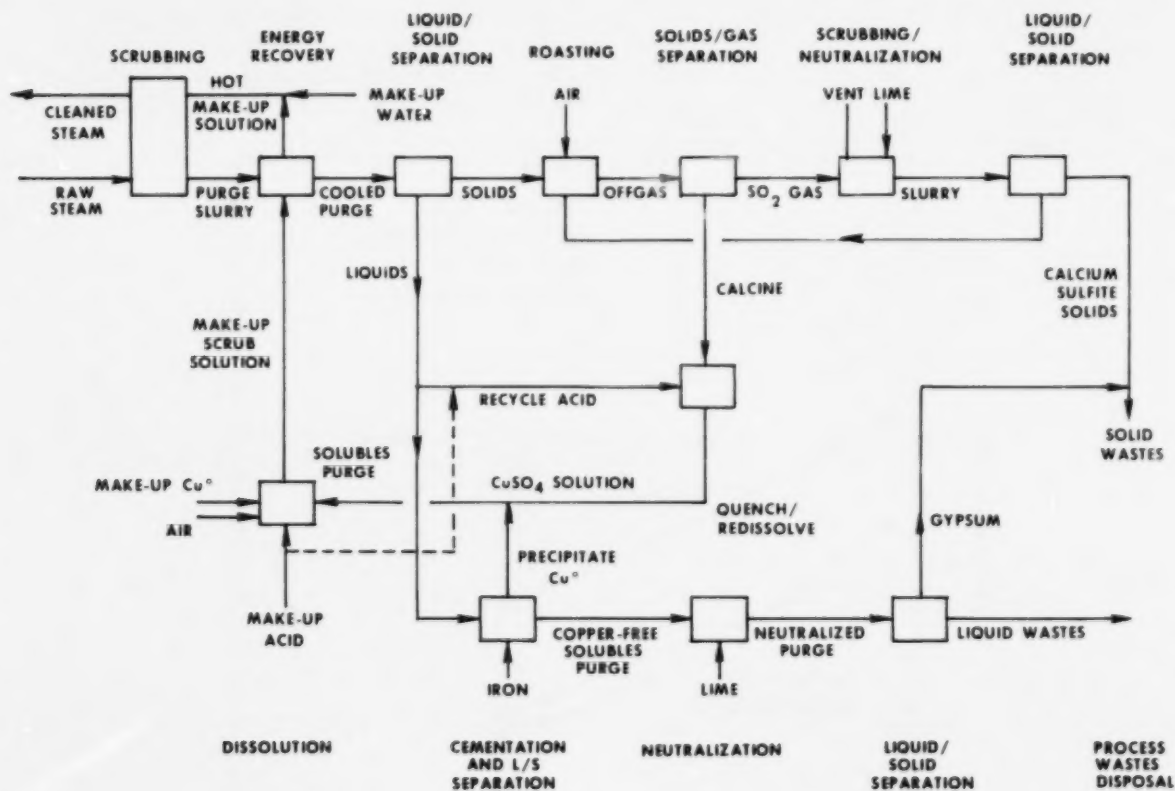


Figure 11. EIC hydrogen sulfide removal process with regeneration by roasting.

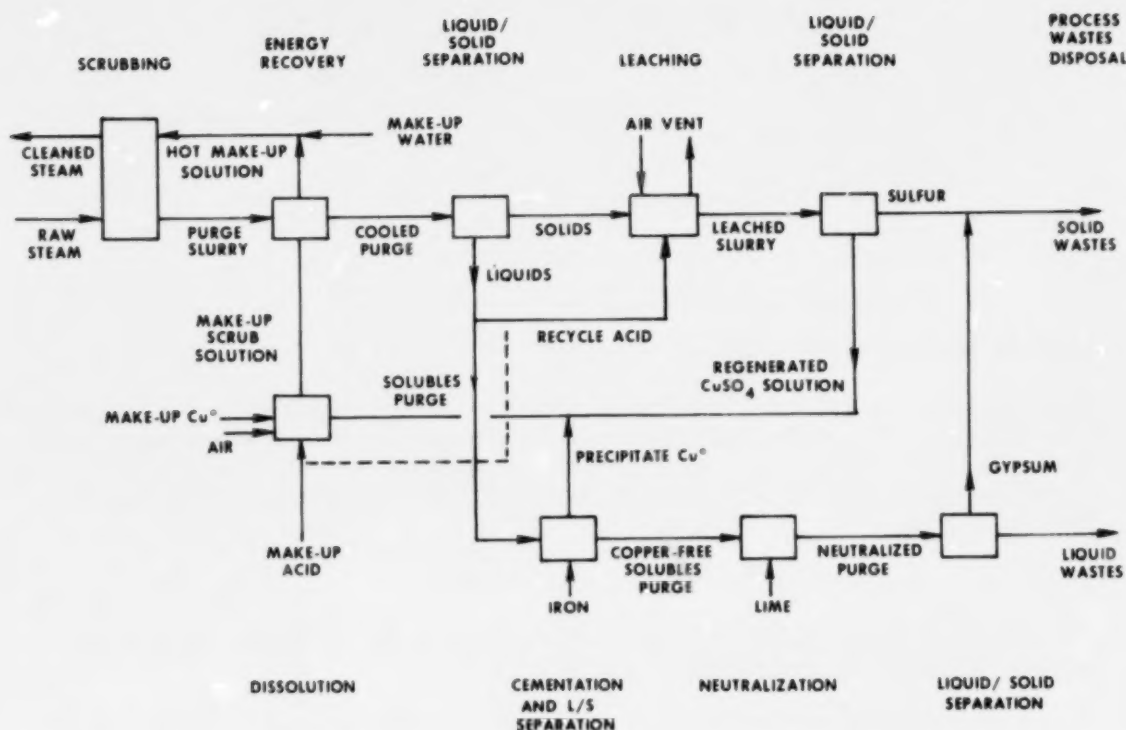
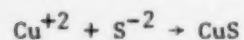
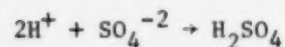
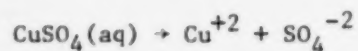
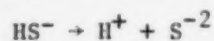
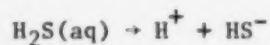
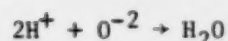
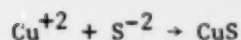
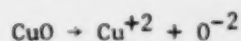
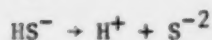
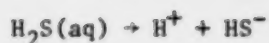


Figure 12. EIC hydrogen sulfide removal process with regeneration by leaching.

The process consists of three primary operations: scrubbing, liquid/solid separation, and regeneration. A packed column, sieve tray column, venturi scrubber, or spray scrubber could be used to provide sufficient contact time and interfacial area for mass transfer between the hydrogen sulfide and copper sulfide to occur. An eight-inch diameter single sieve tray column has been used in field tests at The Geysers. Hydrogen sulfide gas in the geothermal steam is absorbed in an aqueous solution containing dissolved copper sulfate and suspended copper oxide particles by the following reaction sequences:

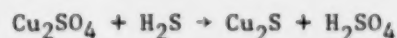


Overall reaction: $\text{CuSO}_4 + \text{H}_2\text{S} \rightarrow \text{CuS} + \text{H}_2\text{SO}_4$



Overall reaction: $\text{CuO} + \text{H}_2\text{S} \rightarrow \text{CuS} + \text{H}_2\text{O}$

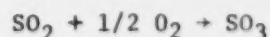
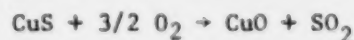
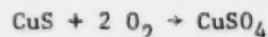
The two reaction chains given above produce a highly insoluble copper sulfide precipitate. The reactions given may be a partial list of the actual total reaction chain mechanism. In addition, some reduction of cupric ions occurs, resulting in a cuprous sulfide precipitate. The overall reaction for this mechanism is:



The scrubbed steam passes through a mist eliminator to remove particulate matter before being expanded in the turbine.

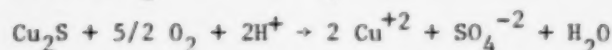
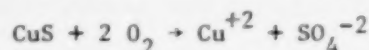
Copper sulfide slurry purged from the scrubber column is pumped to a centrifuge to concentrate the slurry. The regeneration technique used will determine the requirements of the liquid/solid separation step. If roasting is used, a polishing filter may be necessary to remove fines entrained in the recycle stream. If leaching is used for regeneration, unreacted copper sulfides and elemental sulfur will be contained in the residues, thus requiring the use of chemical flocculants together with filtration to obtain acceptable separation and clarification. In order to reduce copper sulfate losses, washing of the cake may be required. Clear liquid from the liquid/solid separation process is returned to the scrubber.

Fluid-bed roasting burns the copper sulfide/cuprous sulfide cake from the liquid/solid separation step with air to produce recoverable copper compounds. The roasting regeneration reactions are as follows:

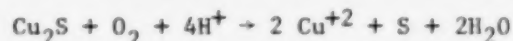
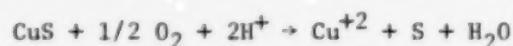


The above reactions are highly exothermic, and self-sustaining after start-up. The solid copper sulfate and copper oxide are slurried and reintroduced into the scrubber for continued hydrogen sulfide removal. The sulfur dioxide and sulfur trioxide produced in the regeneration step are scrubbed by an ammoniacal solution. The liquid discharge stream from the sulfur dioxide scrubber is mixed with cooling tower blowdown and injected.

Oxygen pressure leaching is the second alternative for recovering copper compounds. The copper sulfide/cuprous sulfide cake requires approximately a two to four hour contact time with pressurized oxygen (100 psia) to obtain acceptable conversion rates. The copper sulfide is oxidized to copper sulfate and elemental sulfur, the ratio being a function of residence time, pH, and temperature. If desirable, operating conditions can be carefully controlled to increase elemental sulfur production in the leaching step. The possible reactions for copper sulfate regeneration by leaching are:



The possible reactions for elemental sulfur formation are:



The EIC process was field tested at The Geysers, unit 7 in December 1976. An eight inch diameter single sieve tray scrubbing column was used. Continuous scrubbing of 1000 lb/hr (450 kg/hr) of steam, containing 220 ppm hydrogen sulfide, was accomplished for 30 hours with efficiencies generally over 97 percent. Entrainment of copper from the scrubbed solution into the steam was less than measurable (<0.05 ppm). In addition to hydrogen sulfide, approximately 80 percent removal of ammonia and boric acid was also observed. The field test scrubber was constructed from Carpenter 20 Cb 3 and showed excellent service under the field test operating conditions. Corrosion tests with various stainless steels have resulted in corrosion rates of less than 5 mils per year.

Costs

Installed capital cost and operation/maintenance costs are summarized in the EIC Corporation Annual Status Report³⁷ for a 50 MW geothermal power plant with steam conditions being those encountered for vent gases at the Niland geothermal loop experimental facility located in Imperial Valley, California. Capital costs for EIC units with hydrogen sulfide concentrations differing from that for the Niland facility were computed by utilizing the following formula:

$$\text{IA} = 0.85 \text{ IB} \left(\frac{\text{HA}}{\text{HB}} \right)^{0.6} + 0.15 \text{ IB}$$

HA = Hydrogen sulfide concentration of the desired EIC process.

HB = Hydrogen sulfide concentration for the given case (830 ppm).

I = Capital investment for the desired or given (A or B) EIC process.

Eighty-five percent of the capital investment for the EIC process involves reactors, tanks, vessels, heat exchangers, filters, pumps, and other associated process equipment. The remaining 15 percent of the capital investment

is allocated for the scrubbing tower. It is assumed that the capital investment for equipment associated with the liquid/solid separation and regeneration operations (85 percent of total) vary exponentially with hydrogen sulfide concentration according to William's sixth-tenth rule.³⁸ The capital investment for the scrubbing tower (15 percent of total) is assumed to depend upon steam flow rate and is relatively independent of hydrogen sulfide concentration.

Assumptions used to estimate the annual capital and operation/maintenance costs for an EIC unit are:³⁷

- Amortization period: 10 years
- Maintenance materials: 2 percent of the installed capital cost
- Maintenance labor: 4 operators at \$18,000 per year
1 maintenance man at \$20,000 per year
1 supervisor at \$22,000 per year.
- Electrical power usage: 2,200,000 KWH per year
- Water usage: 10,000,000 gallons (37.85×10^6 liters) per year at \$0.50 per 1000 gallons (3785 liters)
- Chemical and process materials:
 - sulfuric acid - 300 tons (273 metric tons) per year at \$33 per ton (\$36.30/metric ton)
 - limestone - 250 tons (227 metric tons) per year at \$8 per ton (\$8.80/metric ton)
 - precipitated copper - 37.5 tons (34 metric tons) per year at \$1600 per ton (\$1760/metric ton)
 - detinned scrap - 45 tons (41 metric tons) per year at \$200 per ton (\$220/metric ton)
 - miscellaneous - \$19,000

Costs, in mills per KWH, for power generation capacities ranging between 50 MW and 500 MW and a hydrogen sulfide concentration of 830 ppm are given in Figure 13. The cost estimates presented for the EIC process were developed from a specific set of operating conditions and do not necessarily apply to geothermal resources with different operating conditions. At constant flow rates, costs increase with increasing H_2S concentration.

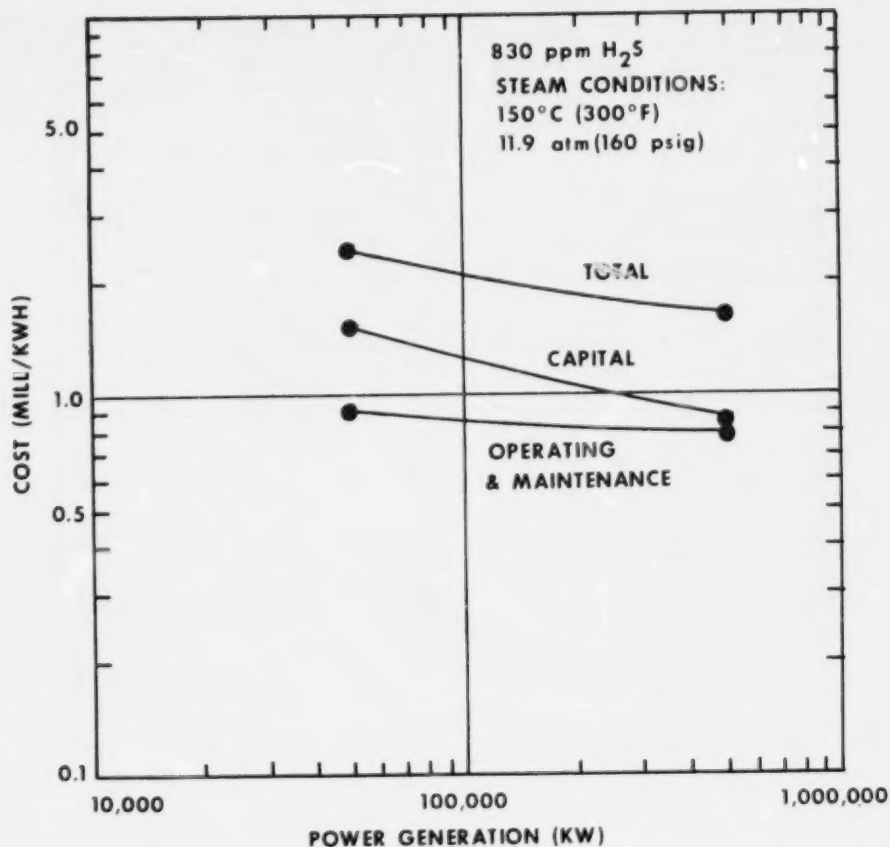


Figure 13. EIC annual cost vs. power generation.

Dow Oxygenation Process

Process Description

The Dow oxygenation process removes hydrogen sulfide from geothermal brine at the wellhead; thus, it is applicable only to liquid-dominated resources. Removal of hydrogen sulfide at the wellhead would provide a less corrosive brine in the pipelines of the gathering field and a less corrosive brine or steam in the power cycle. The Dow process oxidizes the aqueous hydrogen sulfide by injecting oxygen directly into the geothermal brine. Thorough mixing to facilitate contact of the brine and oxygen can be accomplished by using in-line mixers or a cocurrent packed tower. Simplified flow diagrams of these two systems are shown in Figures 14 and 15, respectively. Figure 14 shows that ten in-line mixers are required for a geothermal well with a 1000 gallon (3785 liters) per minute flow rate. This design utilizes the largest available in-line mixer at an acceptable pressure drop.

The oxidation reaction occurs very rapidly, less than one minute for temperature expected for geothermal brines. One proposed reaction chain for the aqueous oxidation of hydrogen sulfide is as follows:

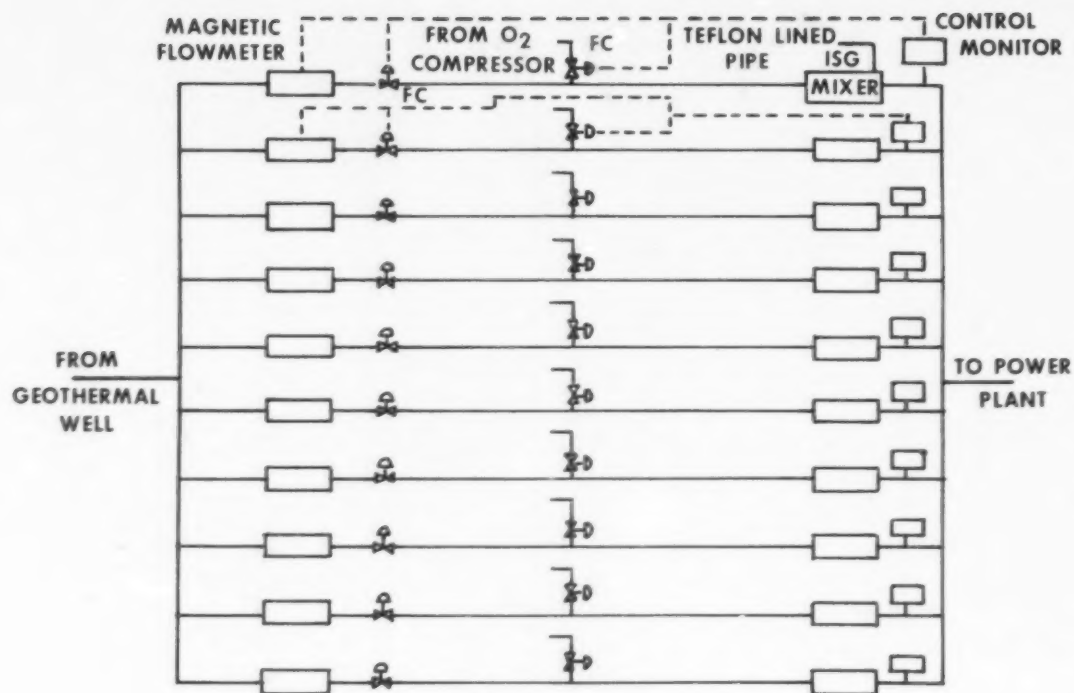


Figure 14. Dow oxygenation hydrogen sulfide removal process with in-line mixers.

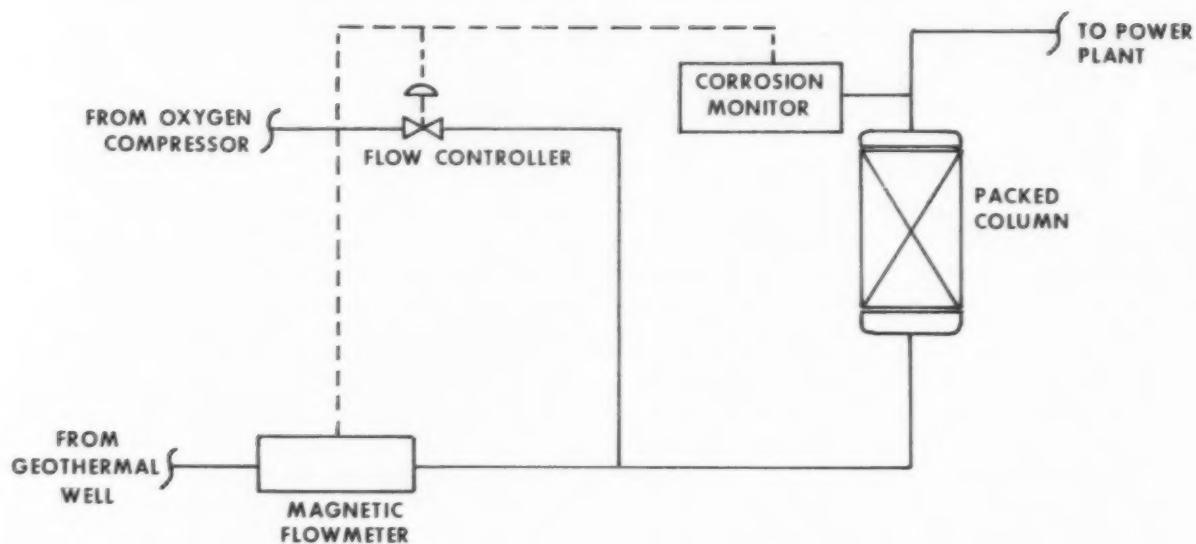
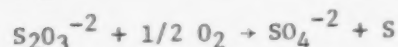
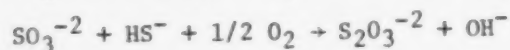
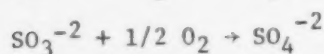
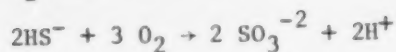
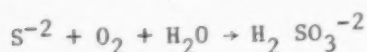
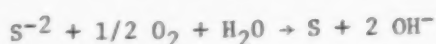
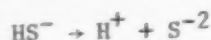


Figure 15. Dow oxygenation sulfide removal process with cocurrent packed tower.



The second reaction given above has an oxygen/sulfide mole ratio of 3:2 (or 1.5:1). However, Dow's laboratory experiments yielded results indicating complete sulfide oxidation occurred at oxygen/sulfide mole ratios of 1.25:1 to 1.5:1, depending on temperature and total dissolved salts in the simulated geothermal brine. Thus, it would appear that other reactions, such as the following, must occur:



The oxygen/sulfide mole ratios for these two reactions are 0.5:1 and 1:1, respectively. The amounts of elemental sulfur, sulfite, and sulfate formed depend upon the oxygen/sulfide mole ratio, but generally 80 percent or more of the sulfide is converted to sulfate ion, approximately 10 percent to elemental sulfur and 10 percent or less to sulfite.

After oxygen is injected into the geothermal brine, and until it reacts with the sulfide in the brine, the corrosivity of the brine increases. This condition requires special materials of construction for both mixing/contact systems. Piping in both systems is teflon-lined between the point of oxygen injection and the mixers or packed tower. The packed tower requires use of a corrosion-resistant alloy. The internal components of the mixers are constructed of teflon.

The in-line mixer system shown in Figure 14 was designed for a well flow rate of 1000 gallons (3785 liters) per minute, thus necessitating the use of ten in-line mixers in parallel, as described previously. In each of the ten lines, a magnetic flowmeter measures the brine flow rate. The flowmeter is electrically interlocked with a control valve, to ensure each line has an equal brine flow rate, and interlocked with a control valve injecting compressed cryogenic oxygen into the brine. The brine-oxygen stream passes through an in-line mixer to ensure complete reaction. Injection of excess oxygen into the brine is also controlled by a corrosion rate monitor located downstream of the mixers. Mild steel piping can be utilized downstream of the mixers. The brine streams are then combined and the brine sent to the power plant. The packed tower system shown in Figure 15 does not require the duplication of equipment and instrumentation necessary for the in-line system. The geothermal well brine flow rate is measured with a magnetic flowmeter and oxygen injection is controlled as described for the in-line

system. The brine-oxygen stream passes through a packed tower to ensure complete reaction. The piping downstream of the tower can be mild steel.

The Dow oxygenation process has been tested on a small 3gpm (11.3 lpm) laboratory pilot-plant scale utilizing the in-line mixer system and shown to be technically feasible. Initially, catalytic agents were believed necessary to achieve acceptable reaction rates; however, addition of catalysts had no measurable effect. Hydrogen sulfide removal efficiencies at 350°F (175°C) and oxygen/sulfide mole ratio of 1.5:1 generally varied from 90 to 100 percent over a pH range of 5.2 to 11.3.

Costs

Preliminary capital cost estimates for both the in-line and packed column systems have been developed by the Dow Chemical Company, based on the results of the laboratory investigation.³⁹ Capital cost for an in-line system was assumed to depend linearly on brine flow rates, because duplication of equipment is required by the present in-line system design. Capital costs for a packed column system with differing brine flow rates were computed by utilizing the following formula:

$$IA = IB \left(\frac{BA}{BB} \right)^{0.85}$$

BA = Brine flow rate of desired Dow process

BB = Brine flow rate of given case (1000 gpm or 3785 lpm)

I = Capital investment for the desired or given (A or B) Dow process.

The capital cost for a packed column system is, therefore, assumed to be exponentially dependent upon the geothermal brine flow rate. The exponential factor was based on that given for a stainless steel packed tower, 36 to 100 inches (90-250 cm) in diameter.³⁸ Capital costs for the in-line and packed column systems were assumed to be independent of the hydrogen sulfide brine concentration. Operation and maintenance costs for electrical power usage and cryogenic oxygen consumption were assumed to be linearly dependent upon the hydrogen sulfide brine concentration.

The following assumptions were utilized to estimate the annual capital and operation/maintenance costs for the in-line and packed column Dow oxygenation systems:

- Amortization period: 15 years
- Maintenance materials: 1 percent of the installed capital cost
- Maintenance labor: 10 percent down time, requiring a two-man crew, earning approximately \$30 per hour
- Electrical power usage: 5 horsepower oxygen compressor required for 1000 gpm (3785 lpm) system³⁵

- Cryogenic oxygen usage: Calculated for an oxygen/hydrogen sulfide mole ratio of 1.25:1.0, with a loss factor of 20 percent
- Cryogenic oxygen cost: \$0.65 per 100 cubic feet (2.83 m^3).³⁵

Because of the relative simplicity of equipment and design for the Dow process, the annual maintenance material cost was taken as 1 percent of the installed capital cost.

Costs, in mills per KWH, for power generation capacities varying from 14.9 MW to 347 MW and with a 500 ppm hydrogen sulfide concentration are shown in Figures 16 and 17. Computations of generation capacities were based on a double flash energy conversion system with 8 percent overall efficiency operating with brine conditions given previously. Cost estimates for the Dow oxygenation in-line and packed column systems have been developed from specific data and conditions, and thus cannot be applied directly to geothermal resources in general.

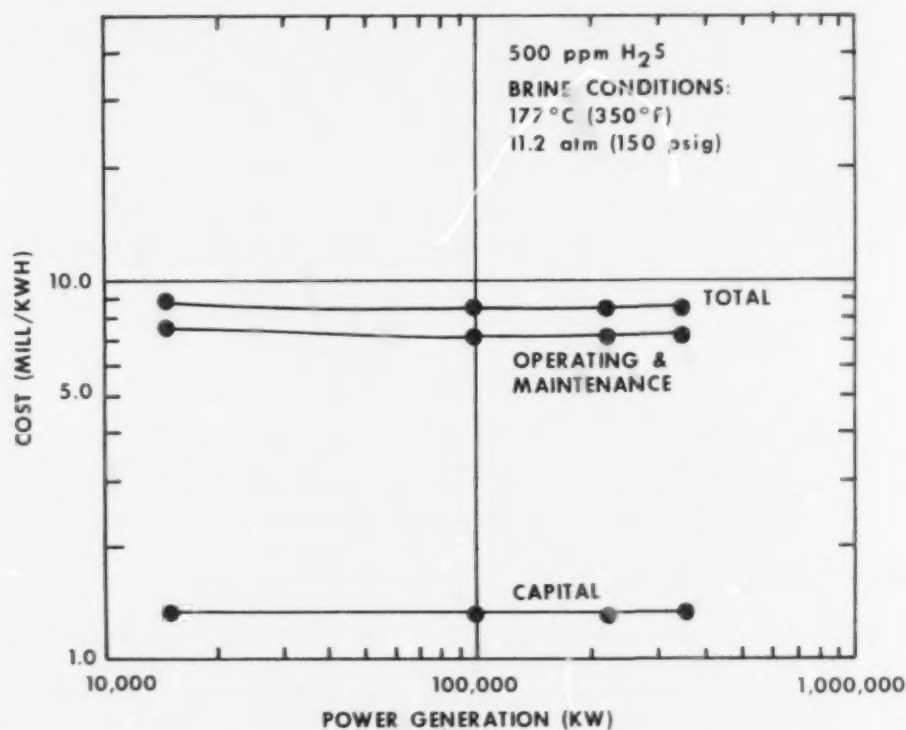


Figure 16. Dow oxygenation in-line system annual cost

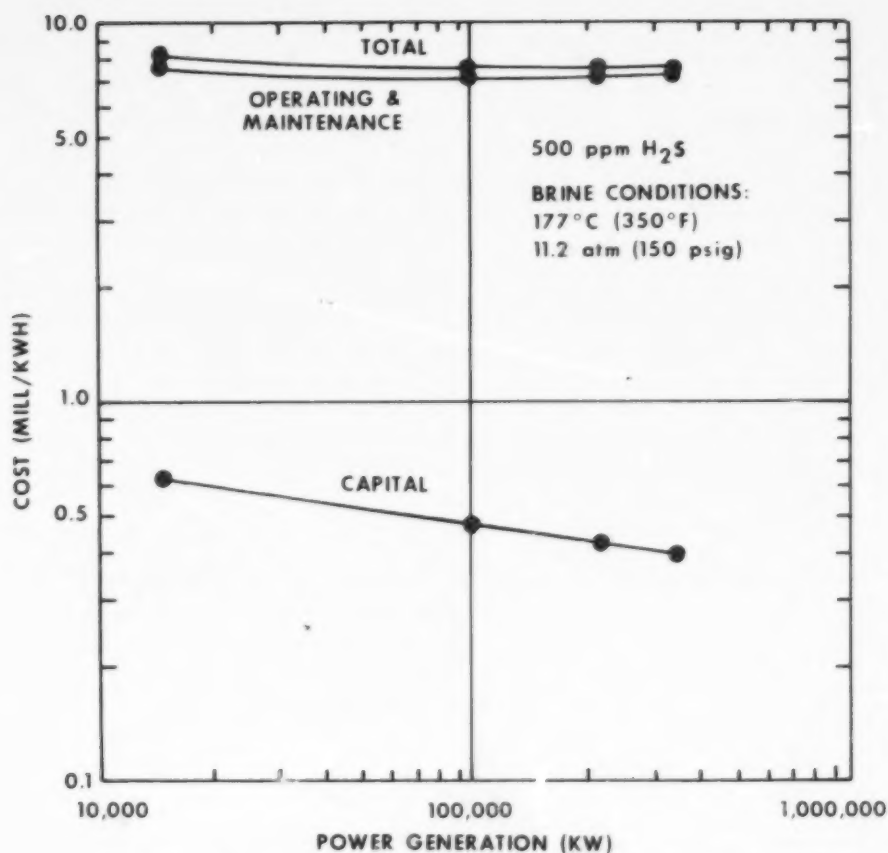


Figure 17. Dox oxygenation packed system annual cost

Other H₂S Removal Processes

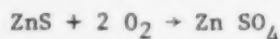
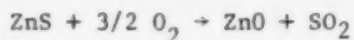
Several other processes are available for the treatment of hydrogen sulfide emissions. At the present time, they do not appear attractive for geothermal applications because of high costs, low efficiency, proprietary nature of the process, or questionable process reactions under geothermal conditions.

Solid Sorbent Process

Battelle Pacific Northwest Laboratories has investigated numerous solid sorbents for the removal of hydrogen sulfide from geothermal steam.⁴⁰ Battelle assumed that the following parameters should be satisfied to establish a technically and economically viable hydrogen sulfide control process: minimum degradation of steam regenerable sorbent; reasonably high sorption capacity; simple regeneration process; quick regeneration; and a stable or useful by-product of regeneration. Zinc oxide produced the most favorable results among the numerous metal oxide and organic amine sorbents tested, because of its good sorbent qualities for removing hydrogen sulfide from simulated geothermal steam. The zinc oxide-hydrogen sulfide adsorption reaction is given below:



Regeneration is accomplished by reaction with oxygen:



The second regeneration reaction producing zinc sulfate is favored over formation of zinc oxide when zinc sulfide is regenerated at low temperatures with oxygen or air. Temperatures in excess of 1200°C are necessary to regenerate zinc oxide directly from zinc sulfide. However, at those temperatures, zinc oxide loses its capacity for adsorbing hydrogen sulfide.

A flow diagram for a sorbent hydrogen sulfide removal process proposed by Battelle is shown in Figure 18. Geothermal steam is introduced from the bottom of a fluidized bed gas-solid contact vessel and hydrogen sulfide is adsorbed by the zinc oxide. The solid sorbent particles suspended in the steam are removed in a cyclonic separator and, if required, a baghouse. The steam is then utilized in the energy conversion system. Solid sorbent is continuously removed from the fluidized bed contactor to the regenerator.

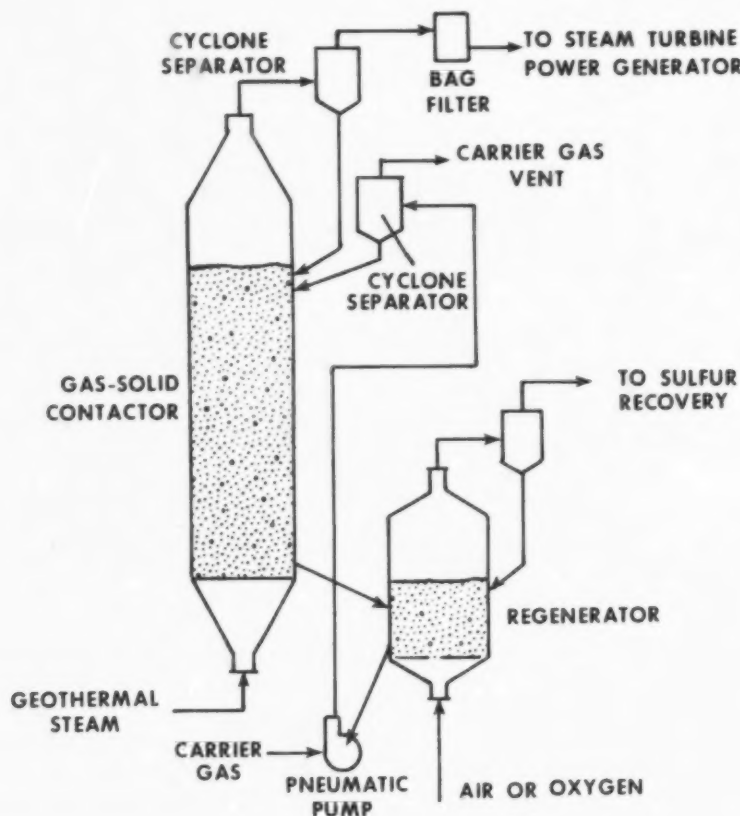


Figure 18. Solid sorption hydrogen sulfide removal process.

Regenerated sorbent is returned pneumatically to the top of the contactor vessel for reuse. Sulfur dioxide generated in the regeneration process requires treatment in a separate sulfur recovery process. Battelle's laboratory investigation has established that a zinc oxide solid sorbent process is not economically viable for the removal of hydrogen sulfide from geothermal steam and recommends that no further work on solid sorbents be undertaken.

Claus Process

The Claus process is probably the best known process for recovering sulfur from gas streams containing hydrogen sulfide and sulfur dioxide. There are several variations of the process; a specific version of the Claus process flow diagram is shown in Figure 19.

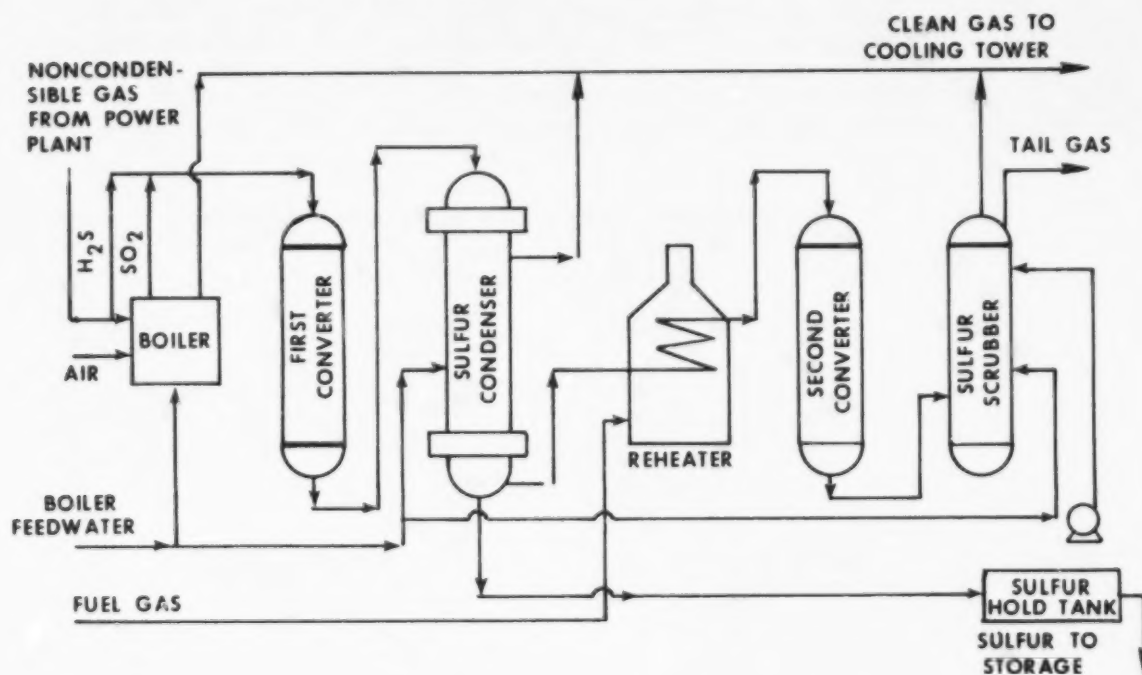


Figure 19. Claus sulfur recovery process.

The process requires a specific concentration ratio between hydrogen sulfide and sulfur dioxide. This ratio is obtained by combusting part of the hydrogen sulfide to produce sulfur dioxide, which is mixed with the feed stream. The hydrogen sulfide and sulfur dioxide are reacted with each other in a series of converters to produce elemental sulfur, which is condensed out of the main gas stream. The converters contain an activated bauxite catalyst which accelerates the following reaction:



A tail gas containing residual amounts of hydrogen sulfide and sulfur dioxide in moderate concentrations is treated by one of the following processes: recycling into the main process upstream of sulfur separation, sent to another treatment process, or diluted into a large volume of stack gases.

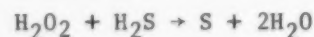
It is doubtful that the Claus process is suitable for removal of hydrogen sulfide from condenser ejector gases. The presence of moisture and carbon dioxide in the feed gas is detrimental to the Claus reaction. Carbon dioxide causes the following side reactions:



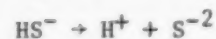
The ejector gases will be saturated and the presence of water tends to reverse the catalyzed Claus reaction.

Hydrogen Peroxide Process

Hydrogen peroxide has been used to remove hydrogen sulfide from various wastewater streams. The applicability of H_2O_2 to geothermal cooling water/condensate is somewhat questionable at this time because of the high temperature environment. Hydrogen peroxide reacts with hydrogen sulfide in an acidic or neutral aqueous solution to produce elemental sulfur and water:



In alkaline solutions ($\text{pH} > 8$), the sulfide ion reacts with hydrogen peroxide to produce sulfate and water:



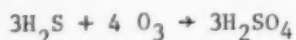
The acidic or neutral reaction is catalyzed by a metal ion, such as the ferrous ion. The rate of the acidic reaction is greatly increased by an increase in temperature. It is interesting to note that four times the hydrogen peroxide is theoretically required to oxidize hydrogen sulfide in an alkaline solution than is required to oxidize that in an acidic solution.

The FMC Corporation has conducted laboratory experiments on oxidation of hydrogen sulfide in samples of cooling water/condensate streams taken from The Geysers power plant.⁴¹ The experiments were conducted with various conditions of hydrogen sulfide solution concentration, pH, temperature, hydrogen peroxide/hydrogen sulfide weight ratio, and ferric sulfide catalyst concentration. The results from the experiments indicate that the hydrogen sulfide oxidation rate increases as a result of increases in (ranges tested given in parenthesis): initial hydrogen sulfide concentration (2.3-12.5 ppm), temperature (40° - 51°C), hydrogen peroxide/hydrogen sulfide weight ratio (0.9-3.9 and 400), and ferric sulfide concentration (0-2.0 ppm). An efficiency of 88

percent was obtained in less than three minutes, without the use of a catalyst, and using a hydrogen peroxide/hydrogen sulfide weight ratio of 1.9 and an initial hydrogen sulfide concentration of 12.5 ppm. The results from the FMC experiments indicate that the use of hydrogen peroxide for oxidation of hydrogen sulfide in geothermal cooling water/condensate is feasible.

Ozone

The use of ozone to oxidize hydrogen sulfide in aqueous solutions has not been adequately investigated to evaluate its applicability for controlling emissions from geothermal sources. Ozone has previously been used to oxidize hydrogen sulfide in the gaseous phase. Elemental sulfur and sulfate are the most likely products of a hydrogen sulfide-ozone aqueous reaction:



Four times as much ozone is required to produce sulfate as is required to produce elemental sulfur. Because of the cost of producing ozone, the economic feasibility of this process may depend on which of the two reactions dominate.

Burner-Scrubber Process

The burner-scrubber process incinerates the noncondensable condenser ejector gases and scrubs the combustion products with cooling water. The hydrogen sulfide contained in the ejector gases is burned to sulfur dioxide. The combustion gases are ducted to a scrubber where contact is made with cooling water, thus dissolving the sulfur dioxide. The dissolved sulfur dioxide reduced the pH of the cooling water, which increases the amount of hydrogen sulfide being removed with the noncondensable gases from the condenser. Thus, more hydrogen sulfide is incinerated, rather than remaining dissolved and being stripped from the cooling water into the air stream in the cooling tower. The sulfur dioxide may also oxidize the hydrogen sulfide dissolved in the cooling water to produce elemental sulfur, providing further abatement of hydrogen sulfide emissions. The burner-scrubber system has been field tested on The Geysers 27 MWe unit 4, with approximately 50 percent of the hydrogen sulfide entering the power plant being removed.³⁰

Catalyst-Scrubber Process

The catalyst-scrubber process is essentially the same as the burner-scrubber system, except the hydrogen sulfide is selectively oxidized to sulfur dioxide with a catalyst developed by the Union Oil Company. Since the hydrogen sulfide is oxidized without combustion, this system is potentially less complex and safer than the burner-scrubber process. The efficiency of the catalyst-scrubber process is also expected to be approximately 50 percent. This process is projected to be installed on The Geysers 53 MWe units 5 and 6 sometime in 1978.

Deuterium Process

The Deuterium process removes hydrogen sulfide from geothermal steam upstream of the power plant. This process is proprietary and a process description is not currently available. The Deuterium Corporation holds the patent for heavy water, production of which requires steam containing hydrogen sulfide.

WATER POLLUTION

Water pollution control technologies include wastewater treatment and ensuing wastewater disposal. The following discussion describes both along with preliminary cost estimates. Depending upon the constituents and the amounts that must be removed, many of the treatment technologies may be used individually or in series. The treatment technologies are those applicable to the removal of suspended and dissolved solids.

Wastewater Treatment Technologies

Sedimentation, Chemical Precipitation, and Filtration

Sedimentation Process Description - Sedimentation is a physical treatment operation that removes settleable solids from wastewaters. It is generally applied to raw wastewaters and to wastewaters that have been chemically treated to precipitate constituents. Any one of several configurations of settling ponds, tanks, and gravity separators may be used for sedimentation. They may be used (particularly gravity separators) to concurrently remove floating materials such as oil. Without other treatment, they will not remove significant amounts of dissolved or emulsified materials.

Sedimentation process efficiency is a function of temperature of the wastewater, the density and size of suspended particles, the amount and character of the suspended material, and settling time. Gravity separation can normally remove 50-65 percent of the suspended solids.⁴²

Chemical Precipitation Process Description - Chemical precipitation is a chemical treatment process involving chemical addition, particle aggregation and particle precipitation. This treatment process is used to assist the sedimentation of colloidal and highly dispersed particles in the waste stream by aggregation and coalescence of small particles into larger more readily settleable or filterable aggregates. Some dissolved inorganic constituents may also be precipitated by chemical coagulants.

The function of chemical coagulations and mechanical flocculation of wastewater is the removal of suspended solids by destabilization of colloids and removal of soluble inorganic compounds, such as trace metals and phosphorus, by chemical precipitation or adsorption on chemical floc. Coagulation involves the reduction of surface charges of colloidal particles and the formation of complex hydrous oxides or precipitates. Coagulation is essentially instantaneous in that the only time required is that necessary for dispersing the chemical coagulants throughout the liquid. Flocculation involves the bonding together of the coagulated particles to form settleable or

filterable solids by agglomeration. Agglomeration is hastened by stirring the water to increase the collision of coagulated particles. Unlike coagulation, flocculation requires definite time intervals to be accomplished.

The more common chemical coagulants used are filter alum, ferric or ferrous sulfate, sodium aluminate, and ferric chloride. Among the coagulant aids used, the more popular ones are lime, soda ash, activated silica, and bentonite or other clays. Generally, chemical coagulants and coagulant aids are added to the waste in a separate chamber in which the waste is mixed rapidly with the chemicals. This system is followed by flocculation chambers and sedimentation tanks.

In general, coagulation reactions vary significantly with changes in pH; therefore pH adjustment of the wastewater may be required to achieve optimum conditions. With proper design of the coagulation/flocculation system and sedimentation tank, removal efficiencies of 80-90 percent of suspended solids and 20-40 percent of dissolved solids can be readily attained.⁴²

Filtration Process Description - Filtration is a solids-liquids separation technique to remove particulate matter from wastewater. It may be used instead of or in addition to sedimentation. In filtration, the wastewater to be treated is passed through a porous medium. Solids separation is accomplished largely by sieving action. The mechanisms involved in the removal of suspended or colloidal material from wastewater by filtration are complex and interrelated. The dominant mechanisms depend on the physical and chemical characteristics of the particulate matter and filtering medium, the rate of filtration, and the biological-chemical characteristics of the water. The mechanisms responsible for the removal of particulate matter vary with each treatment system.

Filtration can be accomplished by the use of: (1) a microstrainer, (2) diatomaceous earth filtration, (3) sand filtration, or (4) mixed-media filtration. The microstrainer is a screen in the form of a partially submerged rotating drum or cylinder. Water flows continuously by gravity through the submerged portion from inside the drum to a clear-water storage chamber outside the drum. Cleaning is carried out by backwashing with sprays of product water. Removal efficiencies have been reported for the following parameters: SS 50-80 percent; BOD 40-70 percent; and turbidity 60-76 percent.⁴²

Diatomaceous earth filtration is a mechanical separation system that employs a filter aid layer of diatomaceous earth. As filtration proceeds, deposited solids build up on the precoat, resulting in an increase in pressure drop. The filter run can be increased by the addition of a filter aid to the body feed to maintain the porosity of the cake. When the pressure drop becomes too great to continue filtration, the filter is backwashed and a new precoat applied. Turbidity and suspended solids removals in excess of 90 percent have been reported.⁴³

Sand filtration is usually employed following chemical coagulation and preceding carbon adsorption or ion exchange. The average filter run before backwashing is related to the solids loading on the filter. Generally, filtration rate is low, and backwashing is frequent because of the rapid build-up

of headloss. However, removal efficiency for suspended solids is usually very good.

Mixed-media filtration was developed in an attempt to approach ideal filtration. Three to four types of media are layered into the filter, graded as to size and density, with coarse low density coal (sp. gr. about 1.0) on top, smaller regular density coal (sp. gr. about 1.6) and silica sand (sp. gr. about 2.6) in the middle two layers, and garnet sand or ilmenite (sp. gr. of 4.2 and 4.5, respectively) in the bottom layer. These different media provide decreasing, coarse to fine, void gradation down through the filter. Large suspended particles in the wastewater are stopped near the surface with finer suspended solids being entrapped in bottom layers, thus providing full bed depth filtration. Effluent suspended solids concentrations less than 1.0 mg/l are readily achieved.⁴⁴

A typical granular media filter is shown in Figure 20. The wastewater is passed through one or several layers of granular material and suspended solids are removed by physical screening, sedimentation, and interparticle action. Headloss increases until breakthrough or removal capacity is reached, and then the filter is cleaned by backwashing.

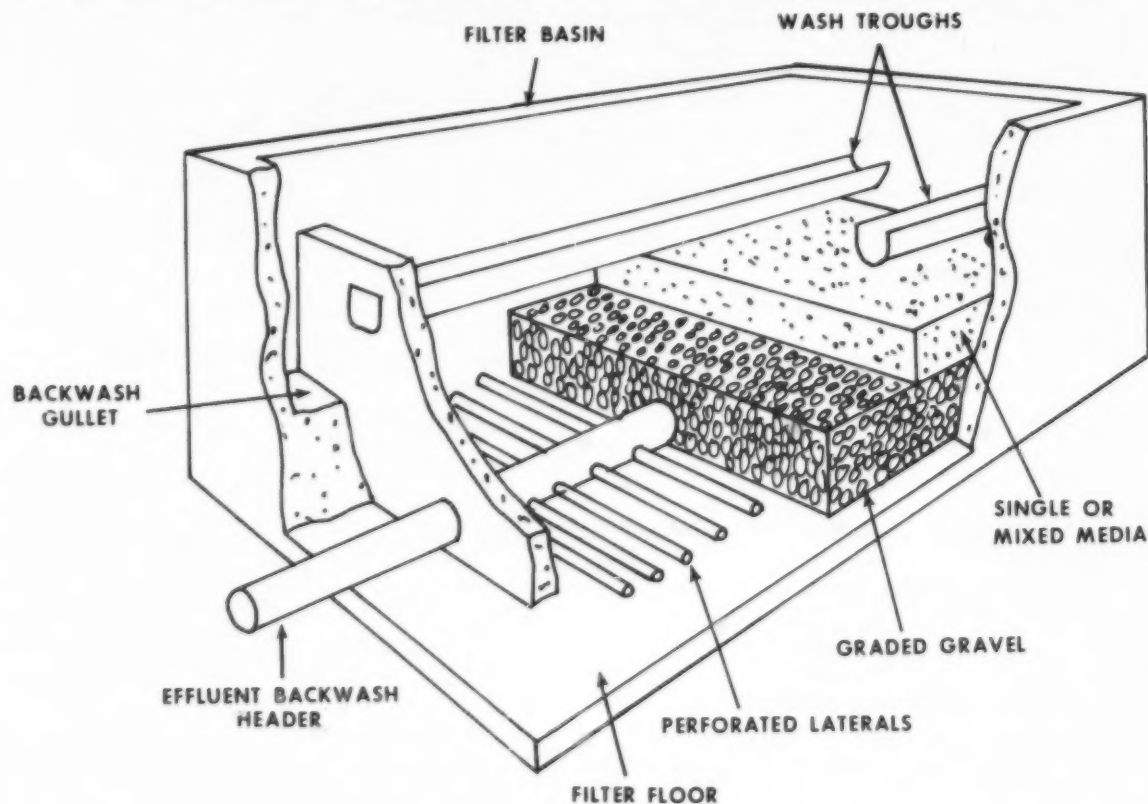


Figure 20. Cut-away view of a granular mixed media filter.

Costs of Sedimentation, Chemical Precipitation, and Filtration

The basis for the development of cost curves is derived from the Van Note, et al., publication "Guide to the Selection of Cost-Effective Wastewater Treatment Systems."⁴⁵

The cost curves for these treatment systems basically consist of three elements: total cost, capital investment, and operation and maintenance (O&M) costs. Total cost is defined as the sum of capital investment and O&M costs. Capital investment is the cost of purchasing and installing the pollution control systems. O&M costs are associated costs for the operation, repair, and routine maintenance of the pollution control equipment. Since the capital investment as well as the O&M costs are flow dependent, empirical equations have been developed for costing these pollution control systems. The total amortized capital cost (TACC) in cents is given by the following equation:

$$TACC = [(BCC) \left(\frac{STP}{177.5} \right) + (LR)(ULC)] \left[\frac{100 + SIF}{100} \right] \left[\frac{1}{3650Q} \right] CRF$$

and the operation and maintenance costs (O&M) are given by:

Fixed operation and maintenance cost in ¢/1000 gal. is

$$(O\&M)_F = (BHM) (MHR) \left(\frac{1}{3650 Q} \right),$$

and variable operation and maintenance cost, ¢/1000 gal. is

$$(O\&M)_V = (BMC) \left(\frac{WPI}{120} \right) \left(\frac{1}{3650 Q} \right),$$

where

BCC = base capital cost

STP = October 1977 cost index for average wastewater treatment plant

LR = land requirement

ULC = land cost

SIF = service and interest factor

Q = wastewater flow (mgd)

CRF = capital recovery factor

BMH = base man-hours

MHR = labor rate

BMC = base materials cost

WPI = wholesale price index

Total capital costs and total operation and maintenance costs were computed in cents per thousand gallons, then converted to cents per thousand liters and plotted in Figures 21 through 26. The cost for the disposal of sludges and brine has not been included. Variations of geographic locations, climatic conditions, land values, and composition of waste streams may invalidate the application of these curves. However, new curves can be developed, based on the equations and assumptions provided above.

In costing the sedimentation basins, a surface loading rate (overflow rate) of 800 gallons/day/ft² (3.26 l/day/cm²) was assumed. The required surface area of the basins is based on this loading rate. Depending on the nature and characteristics of the geothermal fluid, the overflow rate may not be adequate for complete settling of the suspended material. The cost curves developed for chemical precipitation by the addition of lime, alum, or ferric chloride are applicable for geothermal fluids with chemical characteristics approximating those found in municipal wastewaters. The actual amount of chemical dosage for geothermal fluids will have to be determined by jar test of the geothermal fluid. The chemical dosage in this cost analysis assumes 200 mg/l lime addition, and 170 mg/l of ferric chloride and alum addition. The capital costs for both the sedimentation basin and chemical precipitation system include costs for sludge removal devices, piping, pumps, and equipment for sludge thickening.

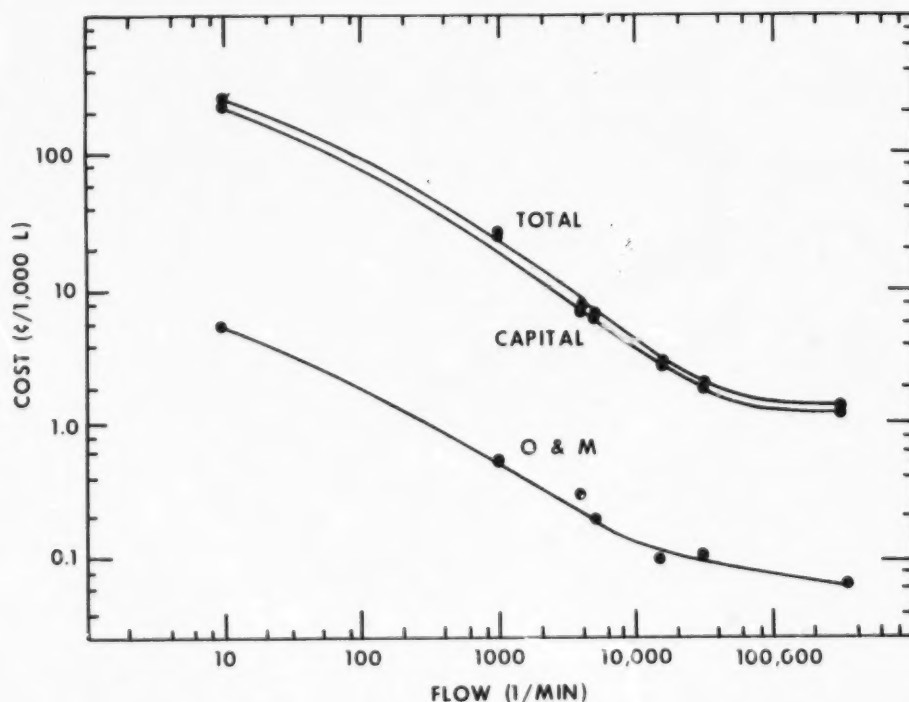


Figure 21. Cost estimates for sedimentation.

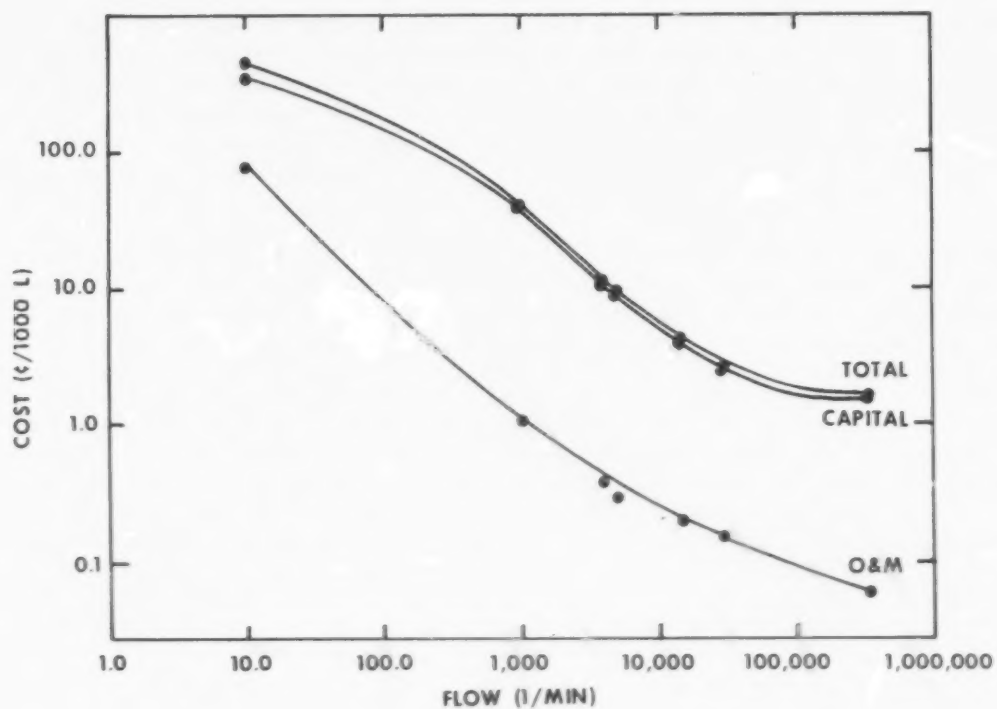


Figure 22. Cost estimates for chemical precipitation with single stage lime addition.

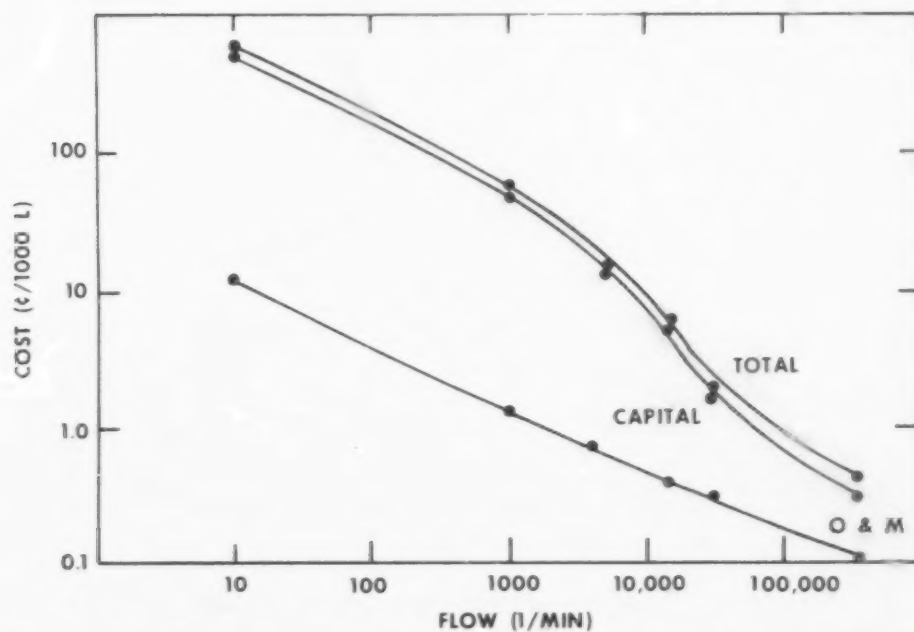


Figure 23. Cost estimates for chemical treatment 2 stage lime addition.

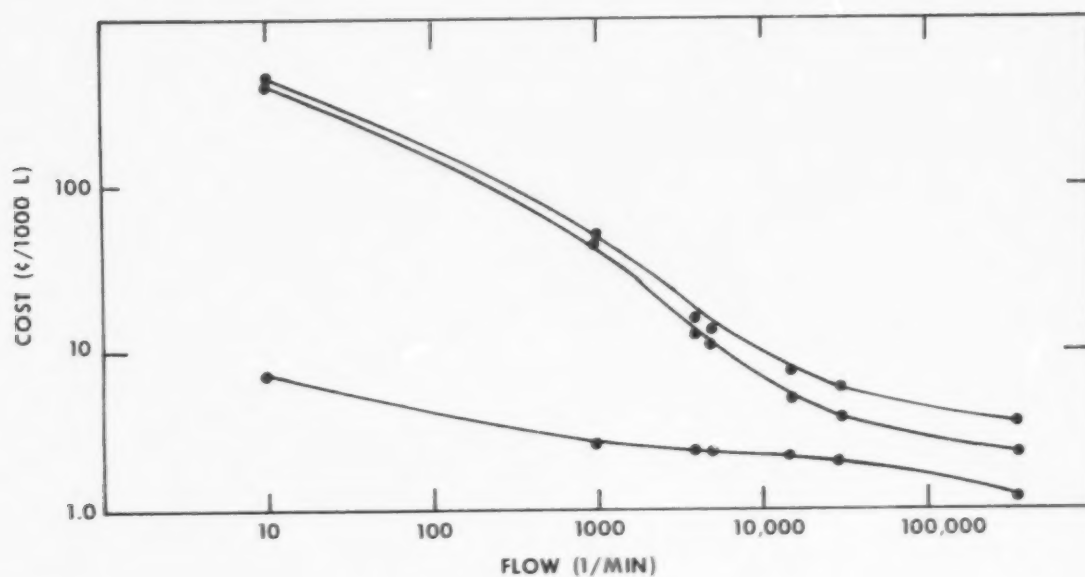


Figure 24. Cost estimates for chemical precipitation with alum addition.

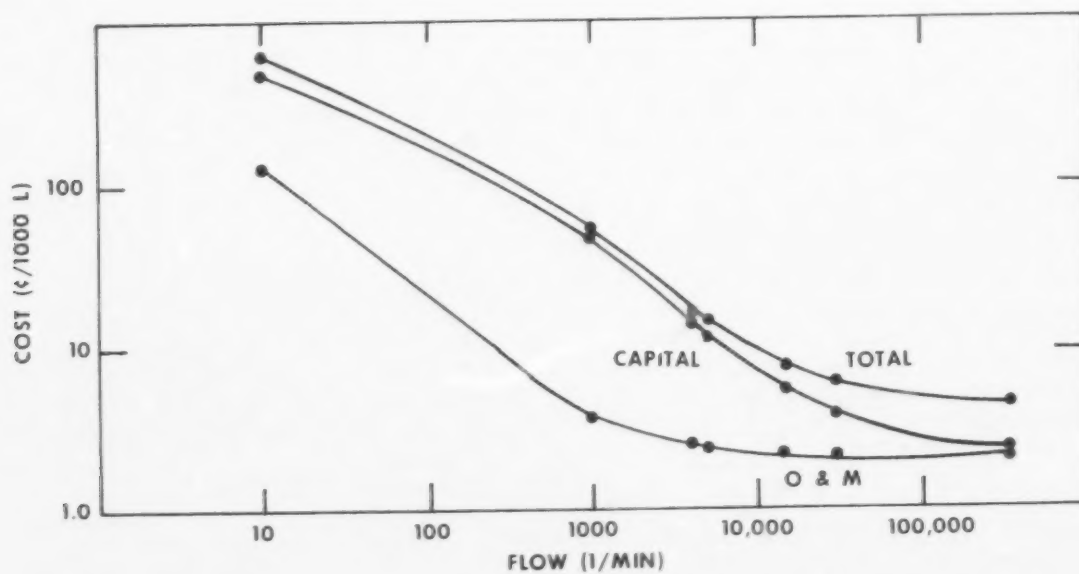


Figure 25. Cost estimates for chemical precipitation with ferric chloride addition.

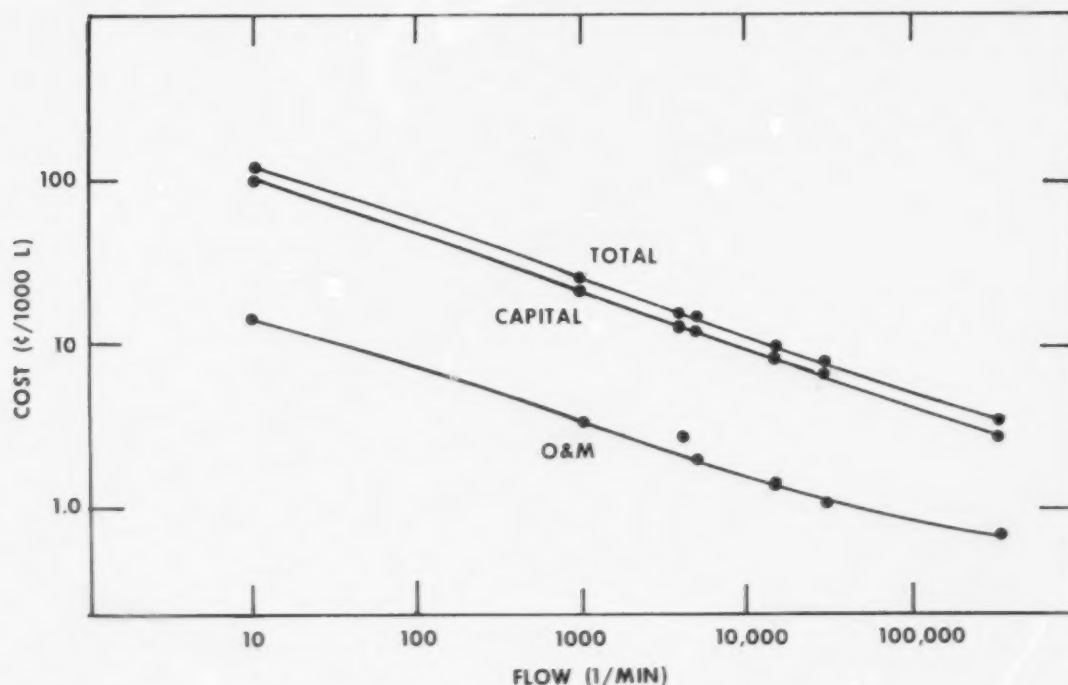


Figure 26. Cost estimates for filtration.

The costing curves developed for gravity filtration are based on a filtration rate of 4 gal/min/ft² (0.016 l/min/cm²). This rate is highly dependent on the nature of the filtering fluid and the characteristics of the filter media. The capital costs include both the filter and the facilities for storage of backwash water (all pumps and piping were also included).

Reverse Osmosis

Process Description - In this process, a portion of the wastewater is forced through a semi-permeable membrane (see Figure 27).⁴⁶ The membrane allows passage of water (permeate) while impeding passage of dissolved ions. The portion of the waste stream not forced through the membrane becomes more concentrated in dissolved solids than the original waste. This concentrated solution (retentate) must be disposed of in some manner. If it is not possible to reclaim the retentate, it must be treated to produce an effluent suitable for discharge.

The membrane is the heart of the reverse osmosis process. Most membranes in current use are cellulose acetate. However, properties of cellulose acetate membranes vary according to the method of manufacture. Therefore, different membranes have different permeabilities for various ions. The feasibility of reverse osmosis as a treatment process is determined by the availability of a membrane which sufficiently limits passage of the ion to be removed while allowing passage of a reasonable amount of water.

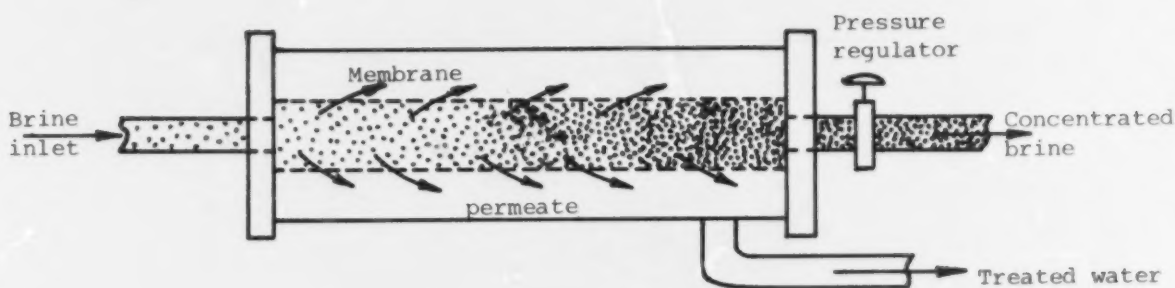


Figure 27. Schematic presentation of reverse osmosis

Given a suitable membrane, the performance of a reverse osmosis unit is largely determined by the split taken between the permeate and the retentate. As a larger fraction of the feed is removed as permeate, the concentration of the retentate increases. The increased concentration difference across the membrane tends to cause ion migration through the membrane. In general, reverse osmosis reduces the dissolved solids concentration to approximately 10 percent of that of the feed solution. Passage of individual ions varies according to the selectivity of the membrane, feed temperature, and pH. Water flux usually increases with increasing temperature, whereas salt rejection remains essentially constant over the normal operating temperature range of 15-30°C. The effect of pH on performance of the reverse osmosis unit is determined by membrane hydrolysis, which also influences salt rejection. Since the membrane is an organic ester, the rate of hydrolysis is pH dependent. Hydrolysis increases at both high and low ends of the pH scale. For this reason, a pH of 3 to 7 should be maintained for optimum membrane operation. Industrial application of the process has shown the following removal efficiencies:⁴² SS 95-98 percent; BOD 95-99 percent; COD 90-95 percent; NH_3 95-99 percent; and org-N, NO_3N , $\text{PO}_4\text{-P}$, and TDS 95-99 percent.

For reverse osmosis to be effective, it is essential that all large suspended particles be removed prior to its application. In addition, most membranes have a maximum tolerable temperature beyond which the membrane loses its effectiveness in retaining the dissolved constituents. Most commercial membranes have a maximum temperature limitation of 200°F. Geothermal fluids may require cooling prior to treatment by reverse osmosis.

Costs - Cost estimates for reverse osmosis were derived from a combination of studies prepared by the Fluids Systems Division of UOP, Inc.,⁴⁷ Los Angeles County Sanitation, and the Orange County Water District Factory 21. Figure 28 is a summary of cost estimates for the reverse osmosis system. The value plotted in the capital investment curve was calculated based on a 20-year plant life, using the capital recovery factor at 7 percent interest rate, 15 percent inflation, and 92 percent plant factor. The operation and maintenance costs include power, chemical, membrane replacement and maintenance, and labor costs. Cost data from the above references were adjusted to the 1977 second quarter costs by using the Marshall and Stevens Process Index (M&S Index).

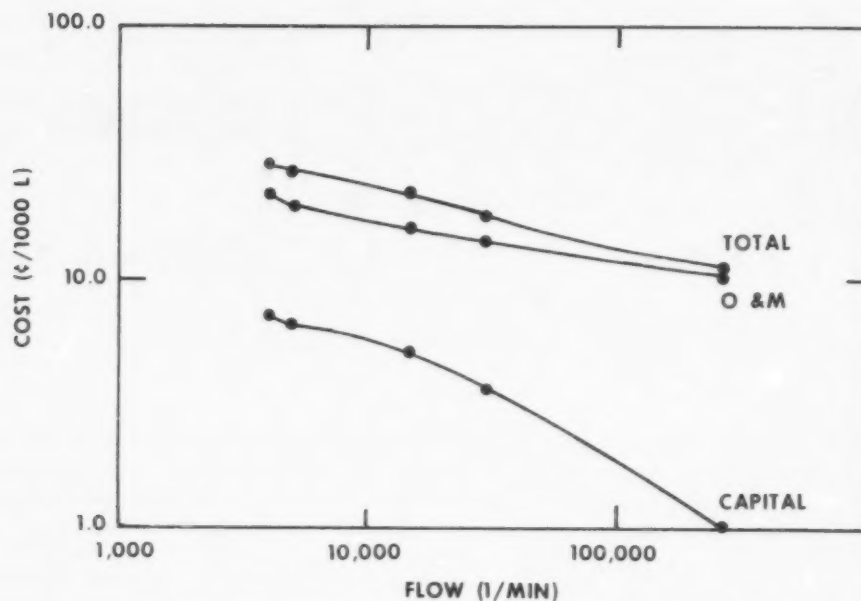


Figure 28. Cost estimate for reverse osmosis system.

Costs of reverse osmosis depend upon the quality and quantity of wastewater to be treated. Pretreatment and disposal of residuals have not been included in the estimates. Membrane life is strongly influenced by the amount of total dissolved solids. The costs shown are for one stage. More than one stage may be required to achieve suitable effluent quality.

Electrodialysis

Process Description - This is an electrolytic process causing separation of ions in the presence of an imposed electrical field. Ions of opposite charge migrate through membranes toward their respective electrodes and the brine is separated into water and a concentrated brine.⁴⁸ The basic principles of electrodialysis are illustrated in Figure 29.

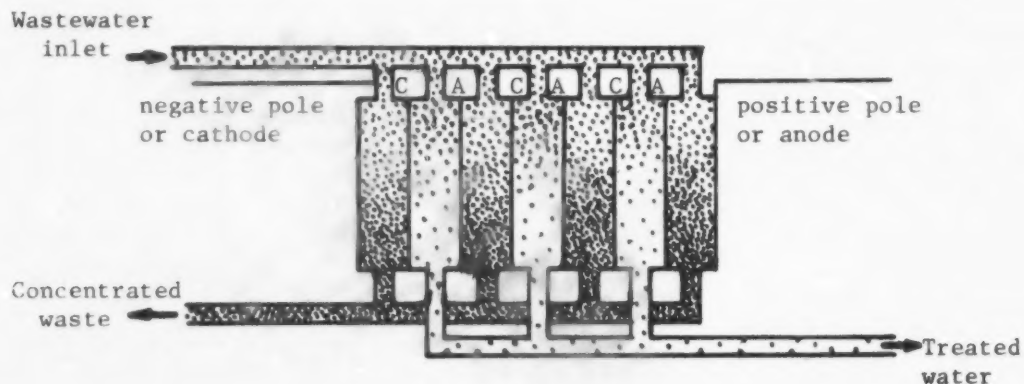


Figure 29. Electrodialysis cell

The electrodialysis system uses a series of alternately-placed anion and cation permeable membranes having a series of compartments. The application of an electrical potential across the system results in the migration of cations to the cathode and of anions to the anode. This creates a series of concentrating and diluting compartments.

Electrodialysis as a wastewater treatment process is in the preliminary development stages. It has been used for the desalination of brackish water. Electrodialysis has not been used extensively in the treatment of industrial wastes.

The membranes used in the process are subject to fouling by any suspended solids or oils (or other organics) in the waste. Membrane life in a system having adequate suspended solids protection must be determined experimentally. Electrodialysis has produced water having a total dissolved solids content of less than 500 ppm. This process is also found to be effective in removing 30% to 50% of $\text{NH}_3\text{-N}$ and $\text{PO}_4\text{-P}$ and approximately 40% of TDS.⁴²

Costs - For electrodialysis systems, the cost estimates were derived from information gathered in the San Francisco Bay-Delta Water Quality Control Program Study.⁴⁹ Data points were extracted directly from the existing graphical plots. Cost and flow units were converted to the metric system. These cost data (capital and O & M costs) were then updated to the present 1977 second quarter costs by again using the M & S Index. The plotted data (shown in Figure 30) were found to correlate relatively well with actual

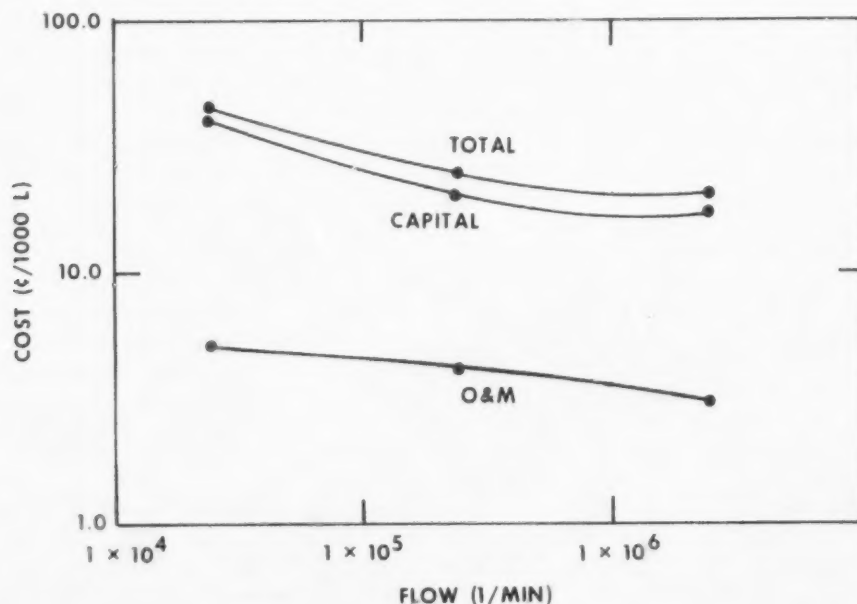


Figure 30. Cost estimates for electrodialysis system

cost data presented by Dryden⁵⁰ and cost curves illustrated by Faber.⁵¹ Unfortunately the assumptions (amortization periods, interest rates, etc.) utilized in the original Bay-Delta Study on electrodialysis systems were not available for inclusion in this report; therefore it is not possible to assess the accuracy and validity of these data points.

As in reverse osmosis, the cost of electrodialysis will depend primarily on the quality and quantity of wastewater to be treated. Pretreatment and residual disposal costs are not included. The costs shown are approximations for one stage. More than one stage might be required.

Ion Exchange

Process Description - This process involves the exchange of objectionable ions in the wastewater with non-objectionable ions such as H^+ or OH^- in the resin material.⁵² Most ion exchange materials are synthetic polymers containing active groups such as HSO_3 and NH_4 to which the exchangeable ions (H^+ and OH^-) are attached. The exchange reaction for removing sodium chromate from surface rinse waters by a combination of cationic and anionic exchange resins can be represented by:



where R^- and R^{++} represent the cationic and anionic exchange material.

When the resins are operating on H^+ and OH^- cycles, treatment with ion exchange also results in the production of deionized water which can be used for process water or in other applications requiring a high quality water.

Demineralization by ion exchange is a process for removing inorganic salts and trace metals from wastewaters. In general, salts are composed of a positive ion of a base and a negative ion of an acid. These ions are removed in two stages: the positive ions by the cation exchanger and the negative ions by the anion exchanger. In the first stage the positive ions of a base such as calcium (Ca), sodium (Na), or magnesium (Mg) are exchanged for hydrogen ions (H) in the cation exchange column, thereby converting these positive anions into their respective acids. In the second stage the negative ions of the acid such as silicates (SiO_3), carbonates (CO_3), chloride (Cl), or sulfate (SO_4) are removed and exchanged for hydroxide ions (OH) in the anion exchange column. This completes the two step removal of the salt. In mixed-bed ion exchangers, as shown in Figure 31, the two steps are combined into one.

Once the demineralized ion exchangers are saturated or excessive leakage occurs they have to be regenerated to allow reuse of the resins. Cation exchangers are regenerated by strong acids (H_2SO_4 or HCl) and anion exchangers by caustic soda ($NaOH$). For continuity of operation during bed regeneration, two trains of ion exchange columns are needed.

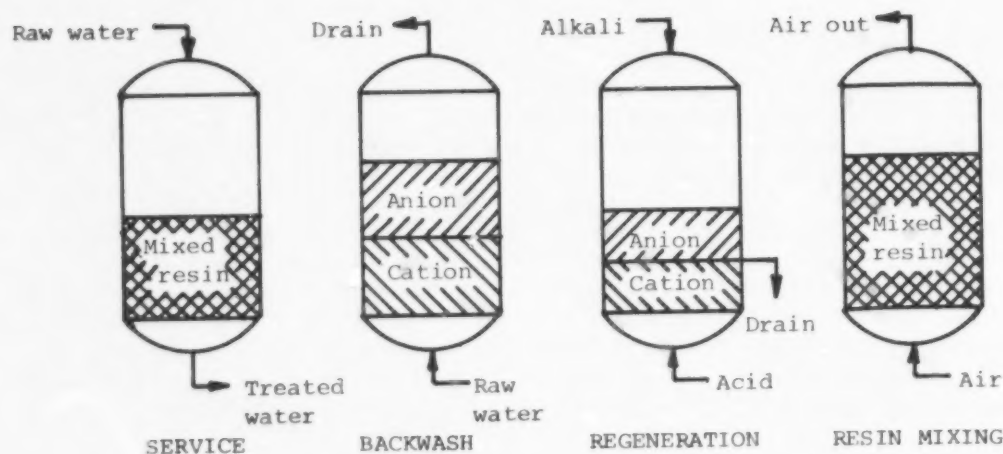


Figure 31. Mixed-bed ion exchange process.

Ideally, ion exchange columns can reduce a given pollutant concentration to essentially zero. In practical applications, depending on the type of resins used, removal efficiencies for total dissolved solids (TDS) have been reported in the range of 80 to 90 percent.⁵² Studies using weak electrolyte ion-exchange resins for the removal of ammonia and phenolics from foul-water condensates of refineries have shown promise.

Costs - The basis of the cost curves in Figure 32 for ion exchange systems is from Van Note's publication.⁴⁵ Chemical costs for regeneration are part of the O&M costs. The actual cost for ion exchange systems is dependent on the exchange resin, the characteristics of the waste water, and the effluent quality required. Pretreatment costs or the cost of disposal of backwash brine have not been included.

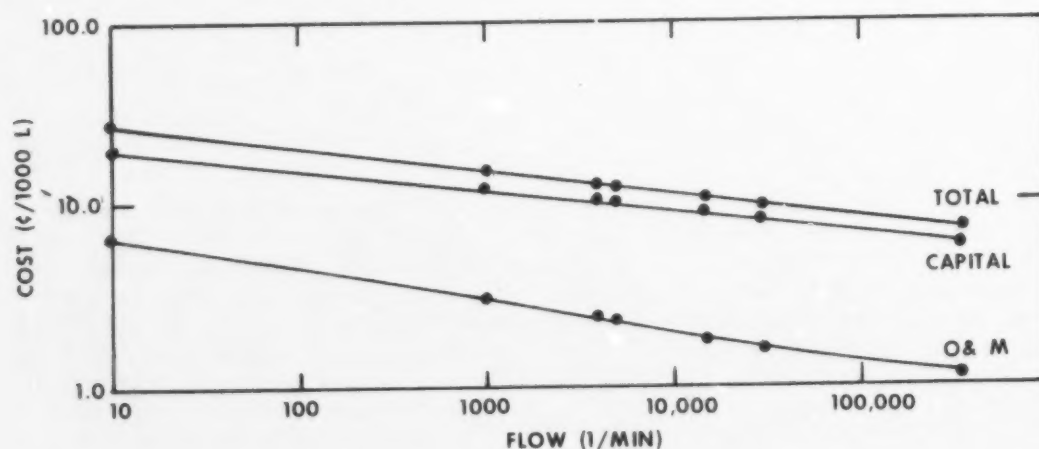


Figure 32. Cost estimates for ion exchange system.

Evaporation - Distillation

Process Description - In evaporation processes components of a liquid are separated by vaporization and condensation. Single- and multiple-effect evaporators are frequently used in the chemical industry to extract water from aqueous solutions.

Evaporators generally use steam as the heat source. Some evaporators may use several stages (termed "effects") to conserve heat. In multiple-effect evaporators (Figure 33), steam is introduced into the first effect in the series, and succeeding effects are operated at lower pressures so that steam condensed from the preceding stage can be used as the heat source in the next. Reduced pressure is usually obtained by exhausting the vapor from the final effect to an aspirator-condenser, such as a jet condenser.

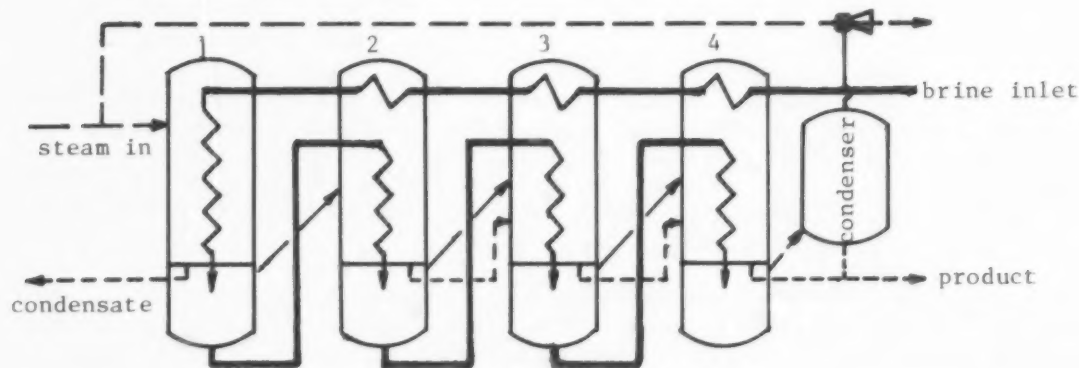


Figure 33. Multiple-effect evaporation.

The multiple stage flash evaporation scheme places all steam heat exchange outside of the evaporation chambers, in a feed preheater. Distillate is flashed from the brine in each stage at successively lower temperatures and pressures (Figure 34). A test facility, using this technology on geothermal brines, is being operated by the Bureau of Reclamation, at East Mesa, California. Its objective is to produce fresh water for augmenting the Colorado River flow and for irrigation. Vapor condensation occurs on exchanger surfaces cooled by inlet water, which is warmed progressively through each stage. Multiple flash evaporators are more economical than multi-effect units, and are frequently used in desalination applications.

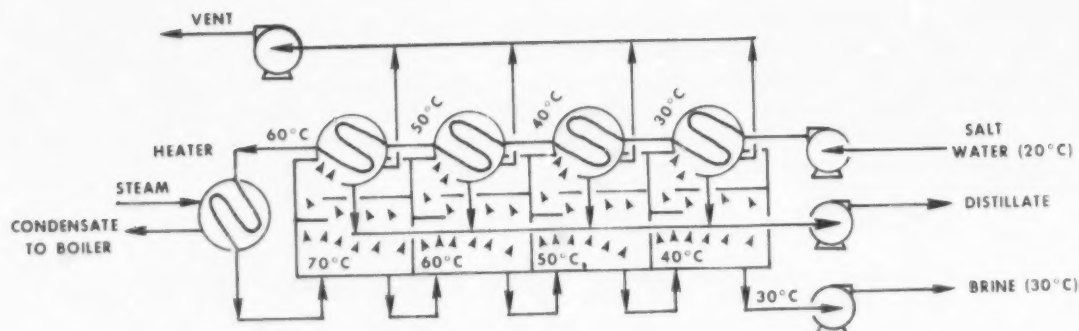


Figure 34. Multiple stage flash evaporation.

Vapor recompression techniques can also be used to conserve heat (Figure 35). The vapor compression method uses mechanical rather than thermal energy, by compressing overhead vapor and using the compressed vapor as a heat exchange medium before it is discharged and used to preheat incoming feedwater. Compression stills may be economically attractive where cheap electrical power is available to drive the compressor. The effectiveness of this method is about the same as that of evaporation ponds, but it is faster and requires heat input.

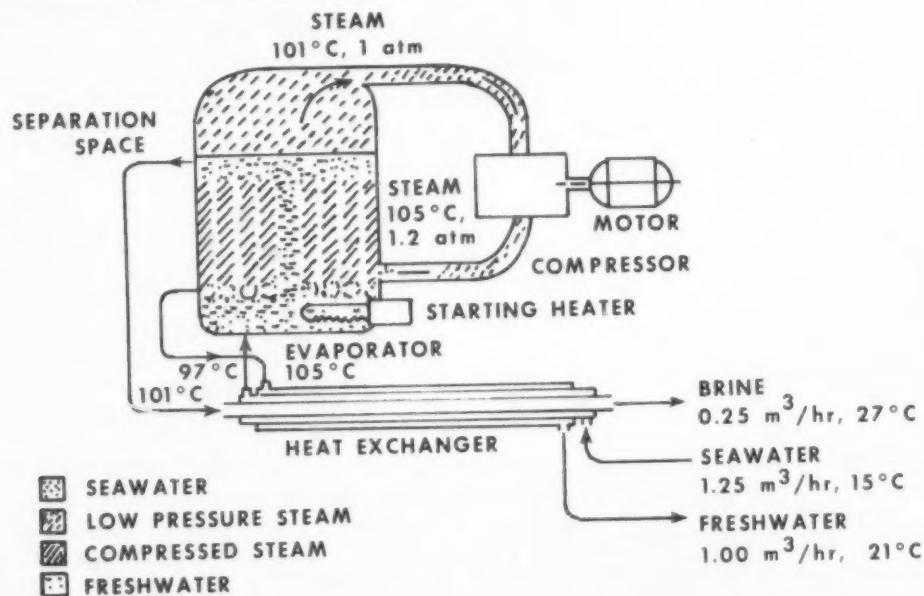


Figure 35. Compression still

These methods are capable of reducing the volume of brine by 70 to 80 percent. The concentrated salt-brine residue must be properly disposed of by either ocean dumping, deep well injection, or after total evaporation, by landfill.

Costs - Evaporation systems costs are dominated by energy requirements, which are directly proportional to the amount of water to be evaporated. The cost of treatment decreases only slightly with increasing throughput (at a fixed percentage of feed to be evaporated). The total costs shown in Figure 36 are a composite of the operating costs and annualized capital costs using the following assumptions:

Electricity @ 4¢/KWH, steam @ \$2/million Btu

8400 operating hours/year, over a 20-year project life (8% rate of return).

Capital and operating costs were obtained from experience in chemical and paper industry practice^{53,54,55} for multi-effect and vapor recompression evaporators. Most cost data for multistage flash units are available from desalination installations.^{56,57}

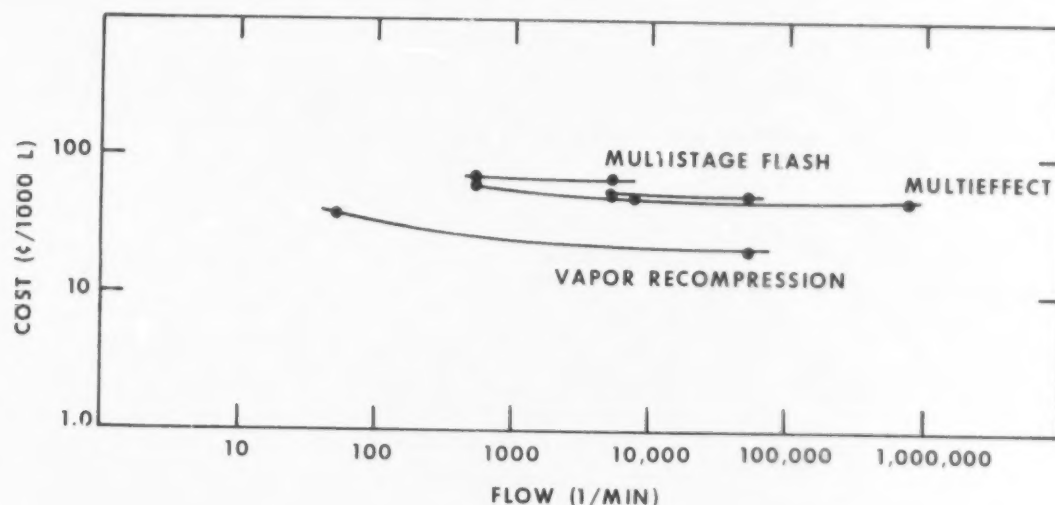


Figure 36. Total costs for evaporation. Basis: 50% of feed evaporated; 40°C feed temperature

The efficiency of multiple stage evaporators (in terms of water produced per unit quantity of steam) improves with increasing number of stages of evaporation or flashing, and a total cost advantage is obtained from the use of ten stages versus three (Figure 36). Even so, the lower cost of vapor recompression units is clearly evident at power costs of 4¢/KWH, and the cost would be even lower with cheap power available from an associated power plant.

Variables which strongly affect evaporation costs include the percentage of feed to be evaporated; the inlet feed temperature; and (in the use of reduced pressure evaporation) the temperature of cooling water. The cost data shown in the figures are based on 50 percent evaporation of feed-water, with an incoming feed temperature of 40°C. There would be considerably more

enthalpy (heat content) available in the incoming feed from the flash down of a geothermal power operation, and this extra enthalpy can be translated into increased amounts of evaporation over the base case. If, for example, an evaporator was designed to evaporate 30 percent of its feed (at 65°C), the same evaporator could yield about 75% evaporation at a feed temperature of 150°C, and 90% evaporation at 225°C.

The total costs for evaporation (20 to 70¢ per 1000 liters of feed shown here are far more than for many competitive methods of wastewater treatment, and some amount of a high-salinity waste brine stream will always require disposal. The conclusion is that evaporation is not an economically viable method for treatment of waste brines.

Other Wastewater Treatment Technologies

In addition to the above-mentioned treatment technologies there are two processes that have been under investigation by the Office of Saline Waters (OSW) for desalination of ocean waters. These include direct freezing/gas hydration and liquid-liquid extraction processes. Direct freezing and the formation of gas hydrates has potential application for separating salt from sea water to produce potable water. However, freezing of high temperature geothermal fluids for the purpose of desalination has technical and economic constraints. Its application to treatment of geothermal wastewater cannot be considered a viable alternative at the present time.

Liquid-liquid extraction involves the use of a solvent (such as diisopropyl amine-propane or N-butanol) to preferentially extract salt from saline water and subsequent evaporation and recovery of the solvent. The use of liquid-liquid extraction for desalting high temperature geothermal fluids would result in technical problems caused by the instability of solvents at high temperature. Its potential application to geothermal fluid treatment is definitely limited and cannot, therefore, be considered viable under current technology.

Specific Chemical Constituents Abatement Technology

The wastewater control technologies presented in the previous subsection deal primarily with process effectiveness and applicability in the removal of gross constituents. A detailed assessment of the removal efficiencies for specific chemical constituents has not been made. This subsection presents a survey of control technologies for the removal of specific pollutants from wastewaters. Table 9 is a summary of this survey. Since most literature findings are limited in information and specific pollutant removal, efforts were made to contact knowledgeable persons in the field, such as equipment vendors, engineering consultants, government regulatory agencies, and academicians, to seek expert opinions on specific applications of pollutant removal from wastewater.

Application of Wastewater Treatment Technologies

Wastewater treatment requirements depend upon the character of the raw wastewater compared to the quality to be maintained in the wastewater disposal

TABLE 9. REPORTED EFFICIENCIES OF CONTROL TECHNOLOGIES FOR
TREATMENT OF SPECIFIC CONSTITUENTS FROM WASTEWATERS
(% removal)

	Sedimentation	Chemical Precipitation	Filtration	Electro- dialysis	Ion Exchange	Reverse Osmosis
TS	20-40	40-60	70-95	30-50	80-90	90-99
TDS	10	20-40	10	30-40	80-90	85-95
Fe	10-30	60-100	70-95	30-40	80-90	95-98
Mn	10-30	65.4-99.4	90-98	30-40	80-90	95-98
B	10	20-40	20-40	10	80-90	60-80
Zn	10-30	90-95	60-85	30-40	80-90	85-95
Ba	10	85-99	80-98	99.9	99	95-98
F	10	99	10	10	80-90	88-92
Pb	10-30	95-97	95-98	30-40	80-90	95-98
Cu	10-30	80-85	90-95	30-40	80-90	95-98
As	10-30	80-98	75-95	30-40	80-90	85-95
Hg	10-30	40-60	70-80	30-40	80-90	85-95
Se	10-30	80-90	90-95	30-40	99.7	85-95
Cr	10-30	60-99	60-99	30-40	80-90	85-95
Ag	10-30	90-99	90-99	30-40	85-95	85-95
Cd	10-30	85-95	90-98	30-40	80-90	85-95

area or receiving media. In order to examine the requirements, three sets of possible raw wastewater constituent characteristics and three sets of possible discharge requirements have been compiled in Table 10. The values shown are not intended to be actual, but probably include the ranges to be considered in geothermal wastewater treatment. Possible ranges of flows for various uses are shown in Table 11. Based on the information shown in Table 10, the required removal efficiencies were calculated, as shown in Table 12, for the various raw levels vs. discharge levels.

In order to simplify the regulatory requirements for achieving the removal efficiencies for each of the constituents in Table 12, it is assumed that the removal of total solids (TS) and the soluble metals (SM) with the most stringent removal efficiency for a given level will concurrently meet all the necessary requirements for that level. This assumption is considered valid because the removal of TS to a specified level will also remove a proportional amount of suspended solids (silica and metal silicates) and dissolved solids (soluble metals, fluoride, etc.). Concurrently the removal of SM with the most stringent removal efficiency generally will also remove SM with less stringent requirements. The only exception is boron, which cannot be effectively removed by any current control technology.

To achieve the three effluent levels, an average value of efficiency was assigned to each of the treatment processes (Table 13). As the efficiencies of most treatment systems vary with the nature and flow conditions of the waste and the engineering design of the treatment processes, these arbitrarily assigned efficiencies are not to be interpreted as definitive

TABLE 10. ASSUMED GEOTHERMAL WASTE BRINE AND SURFACE
WATER DISCHARGE CONCENTRATIONS (mg/l)

Constituent	Geothermal Waste Brine Concentration Level			Surface Water Discharge Concentration level		
	High	Mid	Low	High	Mid	Low
Total Solids	100,000	10,000	2,000	5,000	1,000	500
Iron	1,000	100	10	5.0	1.0	0.5
Manganese	1,000	10	1	1.0	0.1	0.05
Boron	500	10	1	5.0	2.0	1.0
Zinc	500	10	1	10	5.0	1.0
Barium	500	10	1	5.0	2.0	1.0
Fluoride	100	1	0.1	1.0	0.1	0.05
Lead	100	1	0.1	1.0	0.1	0.05
Copper	50	1	0.1	5.0	2.0	1.0
Arsenic	10	1	0.1	0.5	0.1	0.05
Mercury	10	0.1	0.01	0.01	0.005	0.002
Selenium	0.1	0.05	0.01	0.05	0.02	0.01
Chromium	10	0.1	0.01	0.5	0.1	0.05
Silver	1	0.1	0.01	0.5	0.1	0.05
Cadmium	1	0.1	0.01	0.05	0.02	0.01

TABLE 11. GEOTHERMAL WASTE BRINE FLOW RATES AND
LEVELS FOR VARIOUS USES

Conversion System	Flow Rate Liters/Min.	Brine Conc. Levels
Direct Steam Power Generation	4,000-30,000	Mid & Low
Flashed Steam, Binary, Total Flow Power Generation	15,000-350,000	High, Mid & Low
Direct Heating Open & Closed	10-1,000	Mid & Low
Desalination	1,000-5,000	High & Mid

TABLE 12. REMOVAL EFFICIENCIES (%) REQUIRED FOR TREATING
VARIOUS LEVELS OF RAW GEOTHERMAL FLUIDS

Constituent	Discharge Concentration Levels								
	High Level Waste			Mid Level Waste			Low Level Waste		
	1	2	3	1	2	3	1	2	3
Total Solids (TS)	95	99	99.5	50	90	95	0	50	75
Iron (Fe)	99.5	99.9	99.95	95	99	99.5	50	90	95
Manganese (Mn)	99.9	99.99	99.995	90	99	99.5	0	90	95
Boron (B)	99	99.6	99.8	50	80	90	0	0	0
Zinc (Zn)	98	99	99.8	0	50	90	0	0	0
Barium (Ba)	99	99.6	99.8	50	80	90	0	0	0
Fluoride (F)	99	99.9	99.95	0	90	95	0	0	50
Lead (Pb)	99	99.9	99.95	0	90	95	0	0	50
Copper (Cu)	90	96	98	0	0	0	0	0	0
Arsenic (As)	95	99	99.5	50	90	95	0	0	50
Mercury (Hg)	99.9	99.95	99.98	90	95	98	0	50	80
Selenium (Se)	50	80	90	0	60	80	0	0	0
Chromium (Cr)	95	99	99.5	0	0	50	0	0	0
Silver (Ag)	50	90	95	0	0	50	0	0	0
Cadmium (Cd)	95	98	99	50	80	90	0	0	0

TABLE 13. ASSIGNED EFFICIENCIES OF VARIOUS TREATMENT
SYSTEMS FOR REMOVING GROSS CONSTITUENTS

	Efficiencies	
	Total Solids	Soluble Metals
Sedimentation	30%	5%
Chemical Precipitation	50%	80%
Filtration	85%	85%
Electrodialysis	40%	35%
Ion Exchange	85%	90%
Reverse Osmosis	90%	90%
Evaporation	99.9%	95%

efficiencies, but rather as an attempt to demonstrate the number of treatment systems required for achieving each of the specified effluent levels.

Applications of control technologies for achieving the three effluent level requirements from three levels of raw geothermal fluid are illustrated in Figures 37, 38, and 39. These figures depict the treatment systems required for each of the specified effluent levels. Implicit in these illustrations are the following assumptions: (1) pretreatment systems such as sedimentation, chemical precipitation, and filtration do not remove pollutants (TS or SM) more than the assigned efficiencies regardless of the number of identical process units utilized; (2) treatment systems such as reverse osmosis, ion exchange, or electrodialysis can remove pollutants at greater than the assigned efficiencies if a combination of unit stages is used, since the removal efficiencies are cumulative; (3) the sequence of treatment processes are arranged in a way so that residual pollutants are readily removed to their assigned efficiencies by succeeding unit processes; reversing the order of the treatment process sequence will invalidate the assigned efficiencies; and (4) alternative treatment systems may be developed to produce similar removal efficiencies.

As an example, Figure 37 presents block diagrams of the various treatment systems necessary for achieving the various effluent quality levels from a high level waste. For level 1, the required removal efficiencies for both TS and SM are shown immediately below the level 1 requirement. To achieve a removal efficiency of 95% TS, it is necessary to have a sedimentation, a chemical precipitation, a filtration, and a reverse osmosis unit. The percentage of TS removed from the system is depicted by the arrow pointing downward from the specific unit process. The percentage of TS remaining is shown by the arrow pointing to the right. Thus, 30% of TS is removed by sedimentation with 70% remaining in the treated waste. Of the 70% TS remaining, an additional 35% is removed by chemical precipitation. Effluent from the chemical treatment thus contains 35% TS. Filtration then removes another 29.75% TS, and reverse osmosis removes an additional 4.725% TS. At the end of this sequence of treatment, 99.47% TS removal efficiency is achieved and only 0.525% TS remains in the treated effluent. A similar procedure can be followed for SM. These flow diagrams show that the treatment requirements for SM removal are always higher than or equal to those designed for TS removal. It appears logical, therefore, to assume that the effluent water quality requirements for the three levels should be governed by SM removal rather than TS removal for that level.

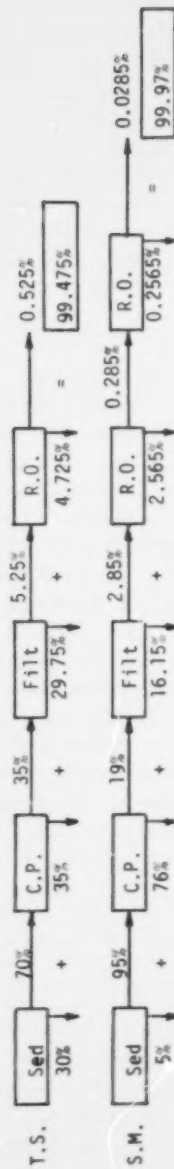
Wastewater Disposal Technologies

Geothermal wastewater requires disposal whether or not it requires prior treatment. In general, the cleaner the wastewater to be disposed of, the easier and less expensive the disposal method. For example, effluents that meet water quality standards can simply be discharged to surface drainage. On the other hand, it is more expensive and more difficult to dispose of wastewater that does not meet such standards; it is these disposal methods with which this discussion is most concerned. It should be borne in mind, however, that these methods may also be used for reasons other than simply

HIGH LEVEL WASTE

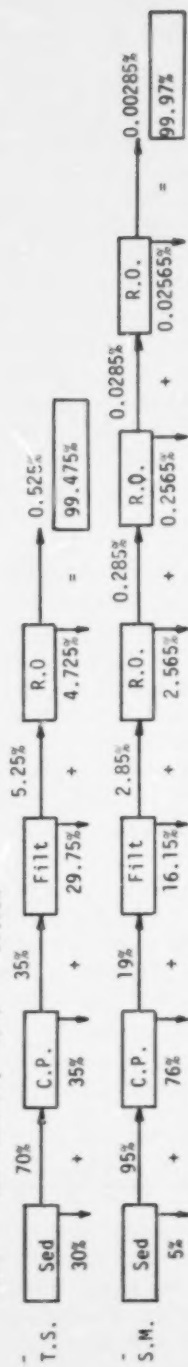
(A) Level 1 Requirement

T.S. = 95% removal; S.M. = 99.9% removal



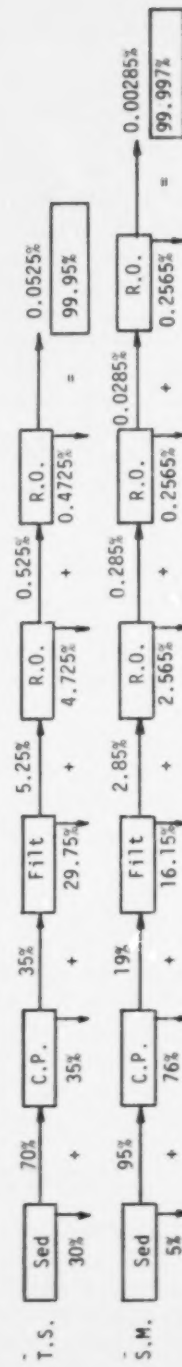
(b) Level 2 Requirement

T.S. = 99% removal; S.M. = 99.99%



(c) Level 3 Requirement

T.S. = 99.5% removal; S.M. = 99.995% removal



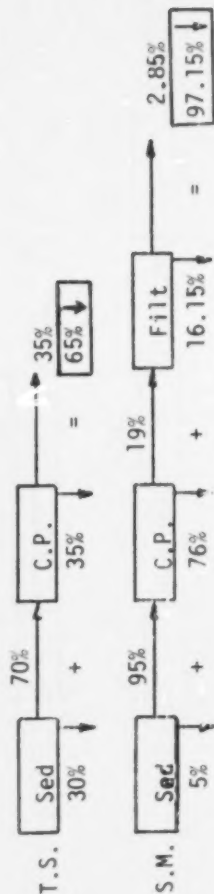
- Legend:
- T.S. = Total solids
 - S.M. = Soluble metal with most stringent requirement
 - Sed = Sedimentation
 - C.P. = Chemical precipitation
 - Filt = Filtration
 - R.O. = Reverse osmosis

Figure 37. Application of treatment technologies for achieving three effluent quality levels from high level waste.

MID-LEVEL WASTE

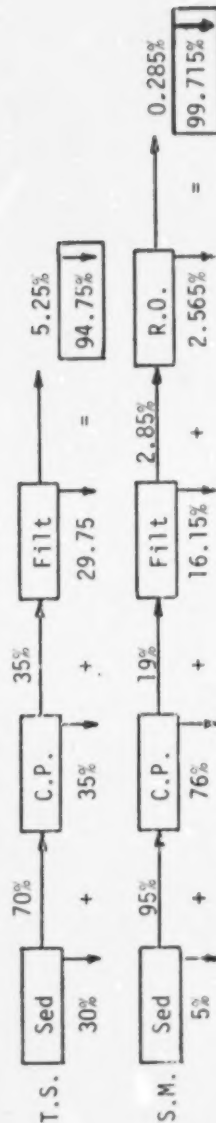
(A) Level 1 Requirement

T.S. = 50% removal; S.M. = 95% removal



(B) Level 2 Requirement

T.S. = 90% removal; S.M. = 99% removal



(C) Level 3 Requirement

T.S. = 95% removal; S.M. = 99.5% removal

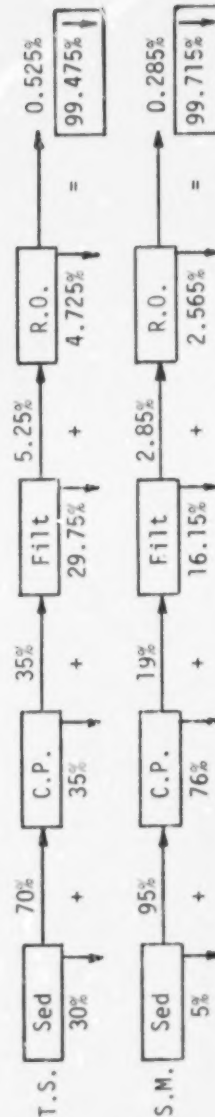
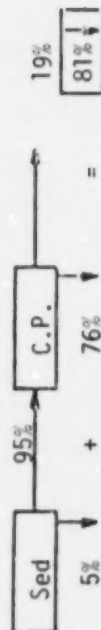


Figure 38. Application of treatment technologies for achieving three effluent quality levels from mid level waste.

LOW LEVEL WASTE

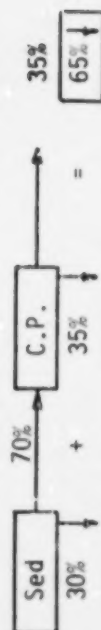
(A) Level 1 Requirement

T.S. = 0 removal; S.M. = 50% removal



(B) Level 2 Requirement

T.S. = 50% removal; S.M. = 90% removal



(C) Level 3 Requirement

T.S. = 75% removal; S.M. = 95% removal

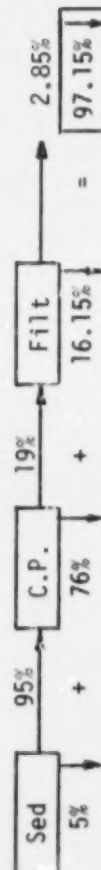


Figure 39. Application of treatment technologies for achieving three effluent quality levels from low level waste.

disposal; for example, injection may be practiced for geothermal reservoir conservation and subsidence prevention.

Subsurface Injection

Methodology - Successful subsurface injection tests have been performed in a number of geothermal fields in the United States and abroad: for example, The Geysers, East Mesa, Niland, and Heber fields in California; the Valles Caldera field in New Mexico; the Matsukawa and Otake fields in Japan; the Wairakei field in New Zealand; the Ahuachapan field in El Salvador, etc. In The Geysers field, return of steam condensate to the geothermal reservoir by injection was started in 1969; about eight billion gallons of condensate have been injected to date. The current daily rate of injection is about 5 million gallons. Besides geothermal, many other industries have adopted subsurface injection of liquid wastes to preventing or control water pollution. The practice is widespread in oil production fields. There are several reasons for choosing subsurface injection as a disposal method. Some of these follow:

- Alternatives to injection are isolating the waste from the surface environment and releasing the waste into surface water bodies. Surface isolation of large quantities of liquid waste generated by geothermal operation is difficult. In most cases, before the liquid waste can be released into surface water bodies, it will require costly treatment. Treatment will create secondary wastes, also requiring disposal.
- Failure to replace reservoir fluid may allow ground subsidence. Subsidence has been observed in the geothermal fields at Cerro Prieto, Mexico, and Wairakei, New Zealand, where fluid reinjection has not been practiced.
- If reservoir fluid is not replaced, the reservoir pressure may decline, unless there is rapid and complete natural recharge. Evidence of complete natural recharge is rare. Any decline in reservoir pressure causes a decline in the productivity of the production wells.
- Injected, cooled geothermal wastewater scavenges heat from the reservoir rock matrix and may be withdrawn again at the production wells. Injected steam condensate may be reproduced as steam. Injection of geothermal waste into the producing formation allows a higher recovery of heat stored in the reservoir.
- Injection into geothermal reservoirs is an effective means of preventing not only chemical, but also thermal, pollution of surface water bodies.

Subsurface injection, if the geothermal fluid is utilized in an open system, will generally be preceded by settling in ponds or tanks to remove suspended solids. Sometimes filters may be used for this purpose. The wastewater might then require chemical or physical deaeration to reduce its corrosiveness. Finally, it is injected into the geothermal reservoir through

the injection well. Injection may sometimes be accomplished by gravity alone, without the need for pumping the waste down the well, because of the higher gravity head of the cooler, denser geothermal waste.

Old production wells may be converted to injection wells. However, wells may be drilled solely for injection. Unless the geothermal reservoir rock is very competent (structurally self-supporting), a cased hole with slotted liner in the injection zone is used. Figure 40 is a schematic diagram of a typical injection well at The Geysers.

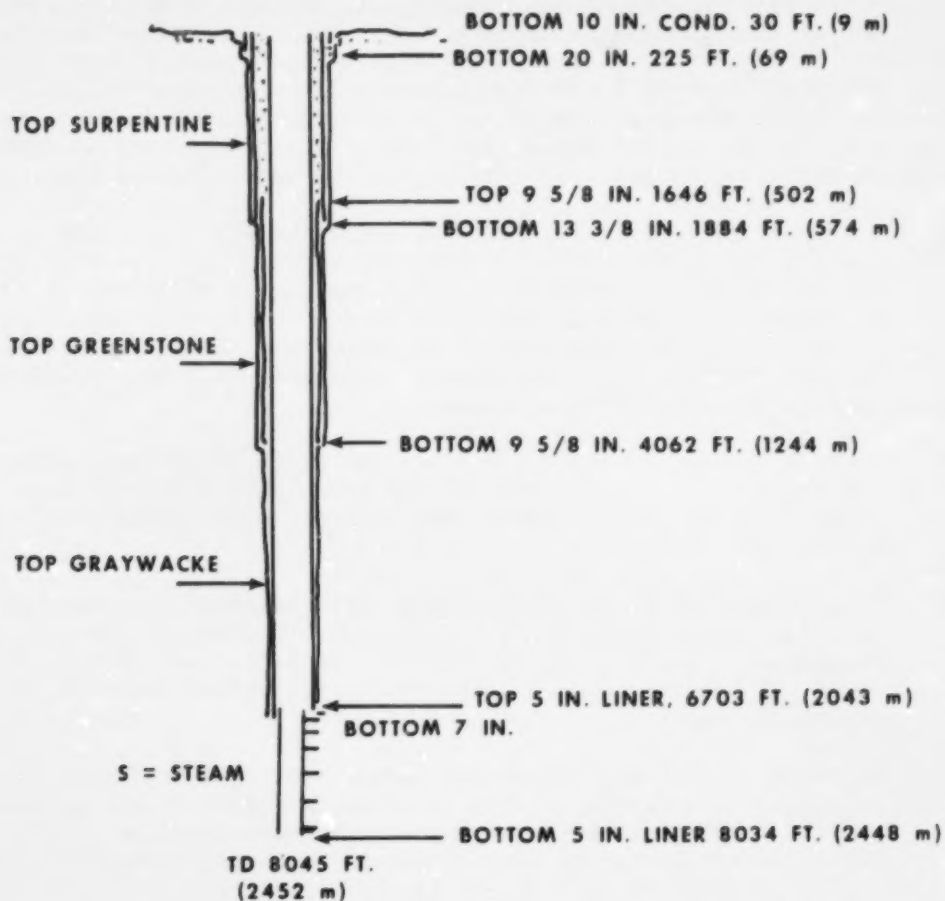


Figure 40. Typical injection well set-up

The primary considerations in evaluating injection potential for a geothermal reservoir are:

- selection of optimum sites;

- cost of drilling and operating the wells compared to other methods of disposal; and
- operational aspects such as the pressure required to inject at a certain rate and the decline in injection rate with time.

The injection scheme should be designed to optimize the travel path and time of flow between injection wells and producing wells, thus preventing rapid cooling of the production water. At the same time, the water should be injected sufficiently into the producing reservoir to minimize the decline in reservoir pressure. The key factor in determining the optimum injection plan is the spatial variation of water temperature and permeability in the reservoir.

Cooling and pressure decline around the injection wellbore may cause formation plugging by the deposition of dissolved and suspended solids, and thus increase resistance to injection. In order to maintain the injection rate, pressure must then be increased. Increase in injection pressure increases operating cost and mechanical problems. If the injection system reaches its maximum pressure capacity, more injection wells may need to be drilled, or the old wells stimulated, to maintain the total injection rate, thus escalating costs. There is no simple way yet to estimate loss of injectivity with time. The only sure means of assessing injection potential is to inject continuously for an extended period, at least a few months, and monitor wellhead injection pressure versus flow rate.

The geological suitability of the reservoir for injection has to be investigated. The reservoir must have a relatively impermeable cap rock to confine the waste from moving upward and polluting ground water aquifers. If fracture zones or faults exist, they may allow upward movement of the waste and consequent pollution.⁵⁸

Where injection causes the pore fluid pressure to exceed the hydrostatic pressure for the area, seismic activity may be induced, if there are pre-existing faults or major fracture zones near the injection zone. At Denver, Colorado, earthquakes were apparently caused by subsurface injection of waste from the Rocky Mountain Arsenal. However, earthquake activity has not yet been linked to injection in any geothermal field. It appears that the possibility of injection-induced earthquakes may be alleviated by minimizing the difference between the injection pressure and the original pore pressure of the reservoir fluids, particularly if there is a fault near the injection area.

Injection wells should be completed carefully to isolate the injection horizon from shallow, fresh water aquifers. Any abandoned well near an injection well may provide a pathway for movement of the waste to shallow fresh water aquifers.⁵⁸ Inadequate cementing behind casings and/or corrosion of liners can result in upward migration of water from geothermal reservoirs.

The efficiency of any injection operation depends to a great extent on the physical, chemical, and thermodynamic characteristics and interrelationships of the waste fluid, the reservoir fluids, and the reservoir rock.

Various types of plugging of the porespace around the injection well bore may occur due to the interaction between the waste and the formation, and the waste and the reservoir fluid. The problems of formation plugging, scaling in the injection lines and well bore, and corrosion of pipes are essentially chemical in nature.

Scaling and plugging may result from one or more of the following:^{59,60} (1) precipitation and polymerization of silica and silicates; (2) precipitation of alkaline earths as insoluble carbonates, sulfates, and hydroxides; (3) precipitation of heavy metals as sulfides; and (4) precipitation of redox reaction products, e.g. iron compounds. Silica and calcium carbonate are the principal materials likely to cause pipe scaling and formation plugging.

Surface pretreatment of the wastewater from geothermal operations may be needed to ensure success of a subsurface disposal operation. Generally the pretreatment would involve one or more of the following:⁵⁹

- storage in impervious impoundments to permit, under quiescent conditions, settling and physical separation of the unwanted components;
- corrosion control by proper pH control, deaeration, and use of inhibitors;
- coagulation and clarification to accelerate gravity sedimentation;
- filtration and addition of bactericide to prevent plugging by bacterial growth; and
- application of electric potential to reduce scaling.

One of the major problems in geothermal energy conversion and injection systems is silica precipitation and scale formation. Monomeric silica in solution will not precipitate nor adhere until it starts to polymerize. Polymerization reduction can be achieved in several ways:⁶¹

- by maintaining a sufficiently high temperature to keep the silica solubility above saturation;
- by reducing turbulence in order to avoid fluctuations in the velocity gradients and collision of particles; and
- by lowering the pH of the solution: a reduction in pH below 6.5 causes a substantial decrease in polymerization.

Silica-laden discharge waters have been successfully treated with slaked lime to precipitate silica and any arsenic, if present.⁴⁴ The wastewater in the Otake geothermal field in Japan is treated with slaked lime and ponded for about one hour. Colloidal silica is formed, polymerization ceases, precipitation and settling takes place, and the water can then be disposed of.⁶⁷ Various scale inhibitors (polyelectrolytes, esters of phosphoric acid, phosphonates, etc.) have been used to slow down the precipitation rate of

calcium carbonate. A glassy phosphate called Calgon has been used as a scale preventer as well as corrosion controller. Application of a negative electrical potential has been found to reduce silica scaling of the Salton Sea geothermal brines.⁶³

Although prevention of scaling can be achieved by treatment, it is also possible to remove scale. Silica scale has been successfully removed from a well-head in the Matsukawa field in Japan by allowing the scale to react with concentrated NaOH.⁶⁴ The scale was completely removed in 30 minutes, although it was necessary to maintain a high temperature and pressure. Shock treatment, subjecting the formation to an almost instantaneous applied pressure differential (implosion) and sustaining the differential temporarily, has been reported to be successful in loosening the material plugging the injection formation.⁶⁵

Geothermal steam condensate often has a significant amount of dissolved H_2S , which may create both scaling and corrosion. The H_2S may be removed by one of the technologies discussed earlier under Air Pollution.

Generally, high salinity accelerates electrical corrosion by increasing the conductivity of the medium. Downhole corrosion rates are a function of temperature, flow rate, well depth, pressure, brine chemistry, pH, and dissolved gases (such as O_2 , CO_2 , H_2S and NH_3). The most common types of corrosion damage to metals used in geothermal environments are (1) uniform attack (ordinary rusting), (2) pitting, and (3) stress corrosion cracking.⁶⁶

Experimental tests of corrosion in the Salton Sea geothermal field have shown that corrosion is generally a problem below 300 meters and increases in severity with depth; above 300 meters, silica scale apparently protects the casing from corrosion. In several downhole tests, little corrosion was observed because of the development of a so-called "hard scale", a friable glassy (amorphous) material, formed as a thin film on the production lines. The composition of the "hard scale" was primarily silica and iron oxide, with some sulfide. Several tests also were done at The Geysers steam field. Corrosion was found to have been caused by sulfuric acid formed by sulfation of part of the H_2S in the steam by oxidation.⁶⁷

Lowering the temperature usually decreases the corrosion rate. Increasing fluid velocity generally increases corrosion attack, with exceptions such as stainless steel. Very high velocities should be avoided where possible because of erosion-corrosion effects. Removing oxygen or oxidizer is an old corrosion-control technique, and may be accomplished by vacuum treatment, inert gas sparging, or oxygen scavengers. Decreasing the concentration of the corrosive and increasing pH (to control acidic conditions) may be effective.

Inhibitors may be used to retard corrosion. There are numerous inhibitor types which can be classified according to their mechanism and composition: (1) adsorption-type inhibitors--organic compounds which adsorb on the metal surface; (2) hydrogen-evolution retardants; (3) scavengers such as sodium sulfite, sulfur dioxide, sodium thiosulfate, and hydrazine, which remove

dissolved oxygen from aqueous solutions; (4) oxidizers; and (5) vapor-phase inhibitors. Inhibitors may, in themselves, be significant pollutants.

Use of alloys does not stop corrosion. It must be remembered that when an alloy or other noble metal is used, any less noble metal directly coupled to it will be sacrificed to corrosion (cathodic protection). Corrosion can be inhibited by couplings of inert materials, such as plastics. Some alloys are more corrosion-resistant than others. For example stainless steels with a chrome content higher than 10% is generally recommended.⁶⁸

Protective coatings may be used to retard corrosion. With any protective coating, however, the protection it affords is directly proportional to the continuity of the coating. The most common coatings are cement, plastic, tar, and epoxy, including teflons. Also, controlled sodium silicate and calcium carbonate scale and glassy phosphates have been used as protective coating materials.

Injection Well Cost Estimates - Capital costs for injection include the costs for drilling, casing and cementing, logging, perforation, well head equipment (including pumps and piping), control systems, and engineering supervision. Operation and maintenance costs consist of expenditures for the operation and routine maintenance of well head equipment, piping, and pumps.

Factors affecting the capital cost of an injection system include hole and pipe diameters, the pumping system required, depth of wells, number of wells, and the hydrology and geology of the site.

The variation of cost per well with well diameter is shown in Figure 41. Pump cost may vary by over 100% per well, depending on the rating and material requirements.

For a given geologic formation, the cost for drilling an injection well increases with depth. The relationships between drilling cost and well depth and lithology have not been clearly established for geothermal applications. Based on one study, the injection well drilling costs for sedimentary lithology vary between \$150 and \$300 per meter depth in 1976 dollars.⁶⁹ The capital cost of drilling and injection in volcanic formations may be 60 to 70 percent higher than in sedimentary formations.

The flow capacity per well determines the number of wells that must be drilled at the site. At a given site the flow capacity depends upon aquifer formation constants that describe the permeability, thickness, and storage capacity of the aquifer. These constants vary markedly from site to site, and, thus far, have been determined at each existing site by pumping tests prior to construction of the injection system.

Because of the wide variations in site specific geology and hydrology, and a lack of complete data characterizing existing wells, injection well cost data have not been usefully parameterized. In the absence of such cost data, the capital cost of injection wells was derived by a simplistic approach involving the selection of a representative well cost using empirical cost data for actual wells. This representative cost was then used to develop

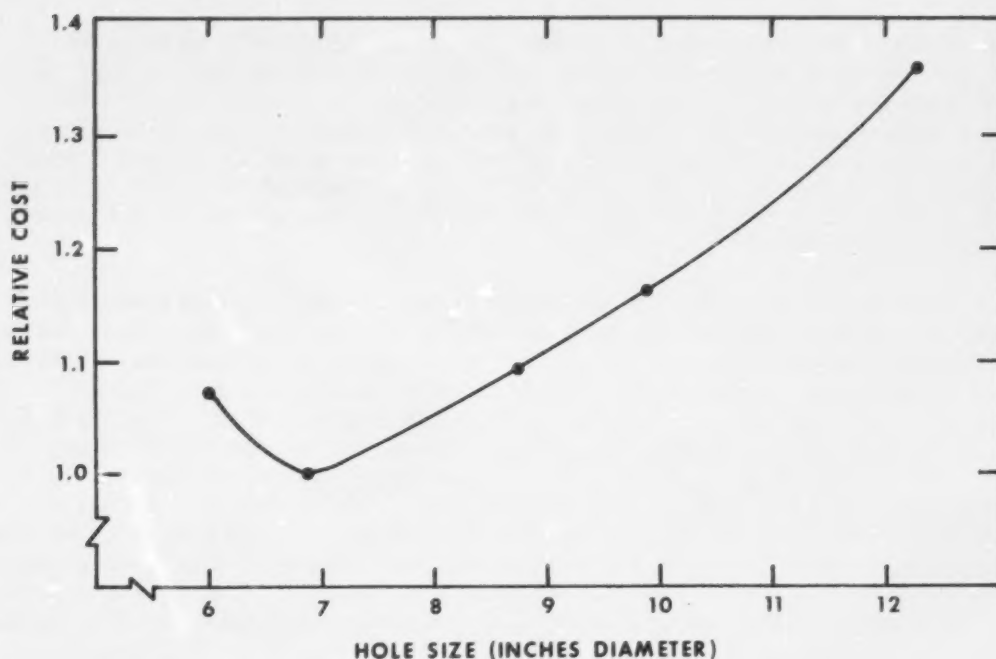


Figure 41. Well hole size cost comparison (capital cost only)

total costs for multiple well systems capable of receiving various wastewater flow rates generated by the four energy conversion processes. The total cost of the well system was also estimated for four selected well capacities representative of existing wells.

Injection well cost data surveyed indicates that the capital investment for an injection well varies from \$400,000 to \$1,000,000. The individual construction costs also vary widely. The average capital cost of an injection well was taken as \$500,000.

The well depth associated with the selected cost data varies from 3,000 to 10,000 feet (914-3,048 m), averaging about 6,000 feet (1,828 m).

The flow capacity selected for a well is based on inspection of the results of a 1971 survey of facilities using injection well systems to dispose of liquid.⁷⁰ At that time, 82% of the injection wells were at refineries, chemical plants, and steel mills. The survey shows that the potential flow for an aquifer can be quite high (16,000 lpm), although the median (512 lpm) indicates that the bias of the survey data is definitely in favor of the lower flows. On the basis of the results of a 1970 survey⁷⁰ of 75 injection facilities, four well capacities have been selected for cost analysis: 200, 1000, 4000, and 8000 lpm.

The calculation of capital cost of various multiple well systems which achieve the expected geothermal wastewater generation rates (up to 350,000 lpm) is shown in Table 14. The total capital cost is determined from the number of wells required to achieve the required disposal flow rate. Total capital cost is then amortized over a 30 year period at an 8% interest rate. Replacement of equipment is considered negligible compared to drilling costs. The demand factor has been assumed to be 80% (i.e., the system is not operating 20% of the time).

The annualized costs for the multiple injection well systems are shown in Figure 42, normalized to each 1000 liters of wastewater flow. Four curves are shown, each representing an injection well system utilizing one of the selected capacities. Clearly, the injection system consisting of larger wells is more economical, since fewer wells must be drilled to accomplish the required disposal rate. However, some caution should be exercised in applying the data of Figure 42. The plots are predicated on the assumption that capital cost of a well is invariant regardless of its capacity. Actually, wells of different capacities, all other site parameters being equal, may use different pumps, different pump injection pressure, or a different hole size. If a different hole size is used to accomplish additional flow capacity, such as from 4000 to 8000 lpm, the relative cost of the larger diameter well would be about 1.2 times that of the smaller well. Still, the cost information developed in Figure 42 is useful to establish preliminary cost estimates and to judge feasibility of multiple well injection systems. For example, it can be seen that the total annualized capital cost of injecting high flow levels of geothermal wastewater from flashed steam plants is relatively low compared to other environmentally acceptable disposal methods.

The operating cost for an injection system will consist mostly of the energy cost for pumping. Routine labor costs will be negligible, and maintenance costs over a thirty-year period will depend primarily on the application and service required. In many cases, repair costs will be almost zero, while in others, anticipated maintenance or repair (due to corrosion, plugging, or wear) will prohibit the use of injection entirely. For the purpose of costing, it is assumed that 0.5% of the capital investment is annual maintenance costs. This corresponds to \$2,500 per well. Depending on the flow temperature and the operating pressure of the injection well, the maintenance costs may vary somewhat.

Energy costs for pumping, in cents per thousand liters, are independent of flow rate, but are instead, a function of the pressure requirement for the particular injection system. This pressure requirement depends on frictional losses in the tubing, elevation changes for the pumped fluid, and the hydrologic pressure requirement (that is, the pressure required to push the waste liquid into the injection aquifer).

Frictional losses in the well tubing area are usually negligible. For a flow rate of 8000 lpm, the losses are 1.3 psi per 100 feet of tubing. On the other hand, the pressure gain due to the elevation head of the waste is 42 psi per 100 feet (9.37 at m/100m) vertical depth (assuming the waste brine has the density equal to that of water at 100°C). The hydrologic pressure requirement (that is, the pressure required to push the waste liquid into the

TABLE 14. CAPITAL COSTS FOR INJECTION SYSTEMS AT FOUR WELL CAPACITIES

Flow (liters/ min.)	Well Capacity: 200 lpm/well				Well Capacity: 1000 lpm/well				Well Capacity: 4000 lpm/well				Well Capacity: 8000 lpm/well			
	No. Wells Req'd	Initial Capital Cost (\$10 ⁶)	Annualized Cost Per Unit of Flow ^b (\$/10000L)	No. Wells Req'd	Initial Capital Cost (\$10 ⁶)	Annualized Cost Per Unit of Flow ^b (\$/10000L)	No. Wells Req'd	Initial Capital Cost (\$10 ⁶)	Annualized Cost Per Unit of Flow ^b (\$/10000L)	No. Wells Req'd	Initial Capital Cost (\$10 ⁶)	Annualized Cost Per Unit of Flow ^b (\$/10000L)	No. Wells Req'd	Initial Capital Cost (\$10 ⁶)	Annualized Cost Per Unit of Flow ^b (\$/10000L)	No. Wells Req'd
10	1	0.5	10.60													
100		0.5	1.06	1	0.5	1.06										
500	2	1.0	0.42	1	0.5	0.212										
1000	5	2.5	0.53	1	0.5	0.106	1	0.5	0.106	1	0.5	0.106				
4000	20	10.	0.53	4	2.0	0.106	1	0.5	0.106	1	0.5	0.0264	1	0.5	0.0264	
5000	25 ^a	12/5	0.53	5	2.5	0.106	2	1.0	0.0422	1	0.5	0.0211	1	0.5	0.0211	
10,000				10	5.0	0.106	3	1.5	0.0316	2	1.0	0.0211	2	1.0	0.0141	
15,000				15	7.5	0.106	4	2.0	0.0281	2	1.0	0.0141	2	1.0	0.0141	
30,000				30 ^a	15.	0.106	8	4.0	0.0281	4	2.0	0.0141	4	2.0	0.0141	
50,000							13	6.5	0.0274	7	3.5	0.0148	7	3.5	0.0148	
100,000							25 ^a	12.5	0.0264	13	6.5	0.0137	13	6.5	0.0137	
350,000										44	22.	0.0133				

a. Arbitrary limit

b. Total cost is annualized based on $C = P(CRF)$, where P = total cost and CRF is capital recovery factor at 8% interest and 30 year period. The demand factor for the well is assumed to be 80%.

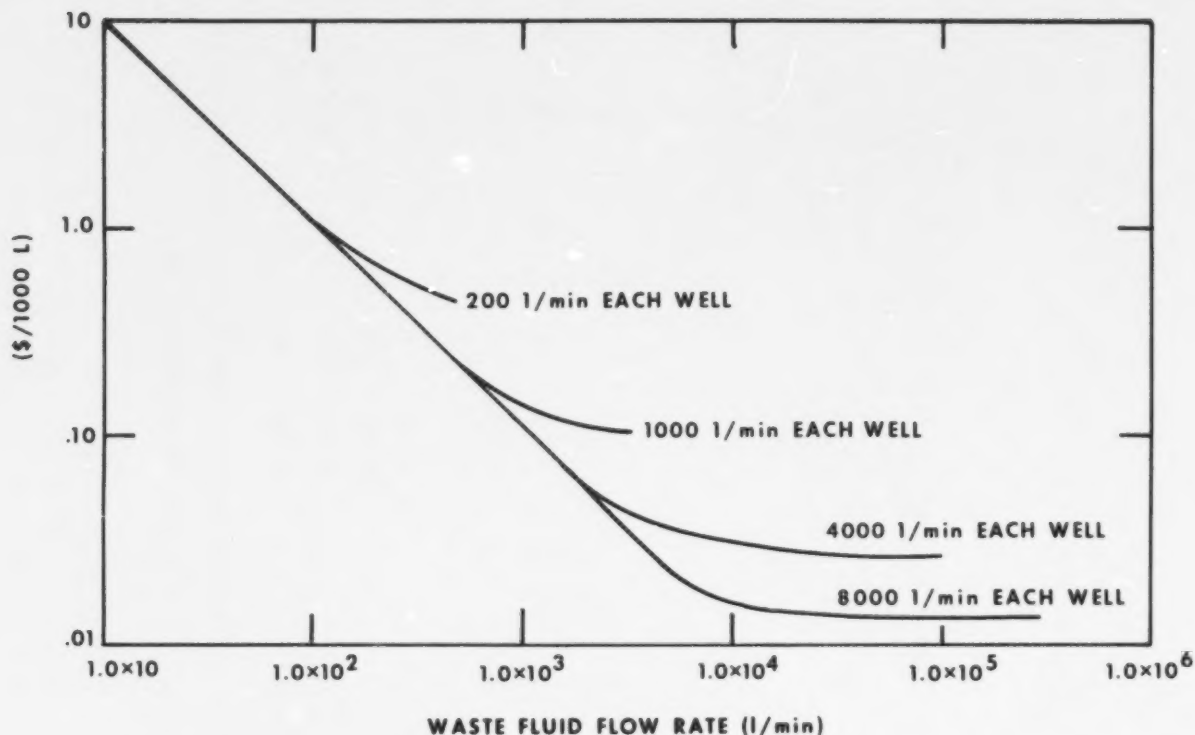


Figure 42. Annualized capital cost for injection of geothermal wastewaters.

injection aquifer) is considered the strongest determinant for pumping energy because of high variabilities in pressure differences.

Table 15 shows the expected energy cost for pumping at various values for the pressure requirement. These pressure values are representative of anticipated requirements, based on surveys of existing injection facilities. In some cases, the initial pressure requirement may be zero because of injection aquifer conditions and/or the pressure gain in the well tubing. However, a pump should still be included in the design to allow for eventual increases in pressure requirements. Pressure requirements can change because permeability of the stratum can change as solids are filtered from the injected waste.

Ocean Disposal

Methodology - The disposal of spent geothermal fluids to ocean waters may be an acceptable alternative in some cases since the most common constituent in geothermal brine is sodium chloride. However, if the geothermal waste significantly increases the salinity or toxicity in the area of the outfall, it will not be acceptable without appropriate prior treatment.

Ocean disposal of spent geothermal fluids would, in principle, be an uncomplicated operation. It involves the conveyance of the liquid, probably by a pipeline, from the geothermal operation to the shore and thence through

TABLE 15. OPERATING ENERGY COST FOR INJECTION PUMPS

Pressure Requirement (psi)	Cost (cents/1000 l)
50	0.714
100	1.43
200	2.86
500	7.14
1000	14.3
1500	21.4
2000	28.6
4000	57.2

a pipe laid on or in the ocean bottom to some distance offshore. At the outfall the wastewater may be released in a simple stream or jetted through a manifold or multiple port diffuser. The diffuser facilitates the mixing of wastewater with sea water, both upward and laterally, thus causing rapid dilution.

Because of the large volumes of geothermal waters that will generally be used per unit of energy extracted, pipelines would be large - perhaps one meter or larger in diameter.

Ocean Disposal Costs - The technical and economic advantages associated with ocean disposal of wastewaters have been diminished greatly in recent years as a result of new and more stringent pollution standards.

In addition to costly pretreatment requirements, costs of conveyance and ocean disposal of geothermal plant wastewaters from sites at least 200 miles (322 km) from the ocean are exorbitant. Approximate costs for conveyance and ocean disposal of wastewaters may be obtained from compilations of existing cost data such as those prepared for the San Francisco Bay and Sacramento-San Joaquin Delta Area Wastewater Management Survey Report.⁷¹ Costs are based upon open country routing, pre-cast pipe foundations, land costs of \$3000/acre, and assumed life of 50 years. Further assumptions are an elevation head between 40 and 100 feet (12-30m), head loss of 1.5 feet per 1000 feet (1.5m/1000m), pump efficiency of 72%, and pump life of 30 years. Costs also include ocean outfall at a depth of 200 feet (61m) with a diffuser; they do not include the cost of any required wastewater pretreatment. Gross estimates are thus provided, in Table 16, for ocean disposal at various flow rates.

TABLE 16. COST OF OCEAN DISPOSAL OF GEOTHERMAL WASTEWATERS

Wastewater Flow l/min	Annualized Cost of Conveyance Lines ^a	Annual Cost of Pumping ^b	Annualized Outfall Cost ^c	Total Cost
1,000	8,000,000	972,000	18,450,000	27,422,000
5,000	11,800,000	3,880,000	29,500,000	45,180,000
10,000	13,300,000	6,920,000	54,200,000	74,420,000
100,000	22,200,000	48,500,000	87,400,000	158,100,000
350,000	35,000,000	136,000,000	113,800,000	284,800,000

^aThe cost of conveyance is based on an assumed open country routing of 200 miles.

^bIt is assumed that wastewater is pumped through an elevation gain of 100 feet.

^cAn offshore outfall distance of 1 mile is assumed. The outfall cost is the sum of the annualized costs for the outfall line and the diffuser.

Evaporation Ponds

Methodology - Where large land areas are available, evaporation ponds could provide a very simple approach to geothermal wastewater disposal. Evaporation ponds are more practical in arid regions where evaporation losses may reach 60 to 100 inches per year (150 to 250 cm/yr).

Construction of evaporation ponds involves excavation and/or diking, depending upon the topography of the area. In some cases, natural depressions may be utilized. In a few instances, it may be possible to enhance natural salt marshes as a wildlife habitat, principally by providing a constant water supply. It is not expected that evaporation ponds would normally have a surface drainage outlet.

Unless the soil is impermeable, evaporation ponds must be lined to prevent ground water pollution. Types of liners include clay, rubber, asphalt, concrete, and plastics.

Table 17 shows the expected water surface area required for evaporation ponds accepting wastewaters from the various geothermal energy conversion processes. The flow approximations represent the median of the range of wastewater production rates associated with the various processes.

Costs of Evaporation Ponds - Cost of evaporation ponds are related to various dependent factors in a recent study conducted for the Environmental Protection Agency.⁷² The data apply to average situations in the United States, and have been based on actual costs of projects over a wide geographic area, including varied construction conditions. The cost estimates developed in the study are representative of national average price levels as of January 1971.

TABLE 17. ESTIMATED WATER SURFACE AREA REQUIRED
FOR DISPOSAL OF GEOTHERMAL WASTEWATERS

Geothermal Conversion System	Median Wastewater Rate, l/min	Water Surface Area, Acres ^a
Direct steam power generation	17,000	1,450
Flashed steam, binary, total flow power generation	80,000	5,335
Direct heating open and closed systems	500	43
Desalination	3,000	257

^aThis is the amount of surface area required to maintain level of evaporation ponds at steady state. The required area is estimated by $A = Q/E$, where A = area required, Q = wastewater generation rate, and E = evaporation rate. It is assumed that losses through the pond liner are negligible.

The total capital investment cost includes the costs of construction, pond liner, embankment protection, engineering, land, and administrative requirements. The total operating and maintenance cost includes the costs of materials, supplies and labor. An estimate of total annual costs versus size of the evaporation pond is provided in Figure 43. Variations in these costs are to be expected with variations in the controlling factors.

Land Spreading

Methodology - Land spreading is a treatment method that relies primarily on biodegradation of the waste constituents. Inorganic wastes, such as those found in geothermal wastewaters, may not be suitable for land application. Significant concentrations of heavy metals would accumulate in the soil, posing threats to plant and animal life, and surface and ground water uses. The hazards of disposing of non-biodegradable materials on land are causing increasing concern, and regulations are becoming more restrictive.

Spraying on irrigable land, wooded areas, and hillsides has been used primarily for the disposal of municipal wastes. Treated effluents have been used for golf course and park watering. The amount of wastewater that can be disposed of by spraying depends largely on the climatic conditions, the infiltration capacity of the soil, the types of crops or grasses grown, and the quality standards imposed where runoff is allowed.

In general, spraying systems may be classified as either low rate or high rate systems. Low rate systems utilize wastewater application rates of approximately 2 to 10 ft/yr, (0.6-3m/yr) whereas high rate systems achieve application rates of 150 to 350 ft/yr (45-107m/yr).

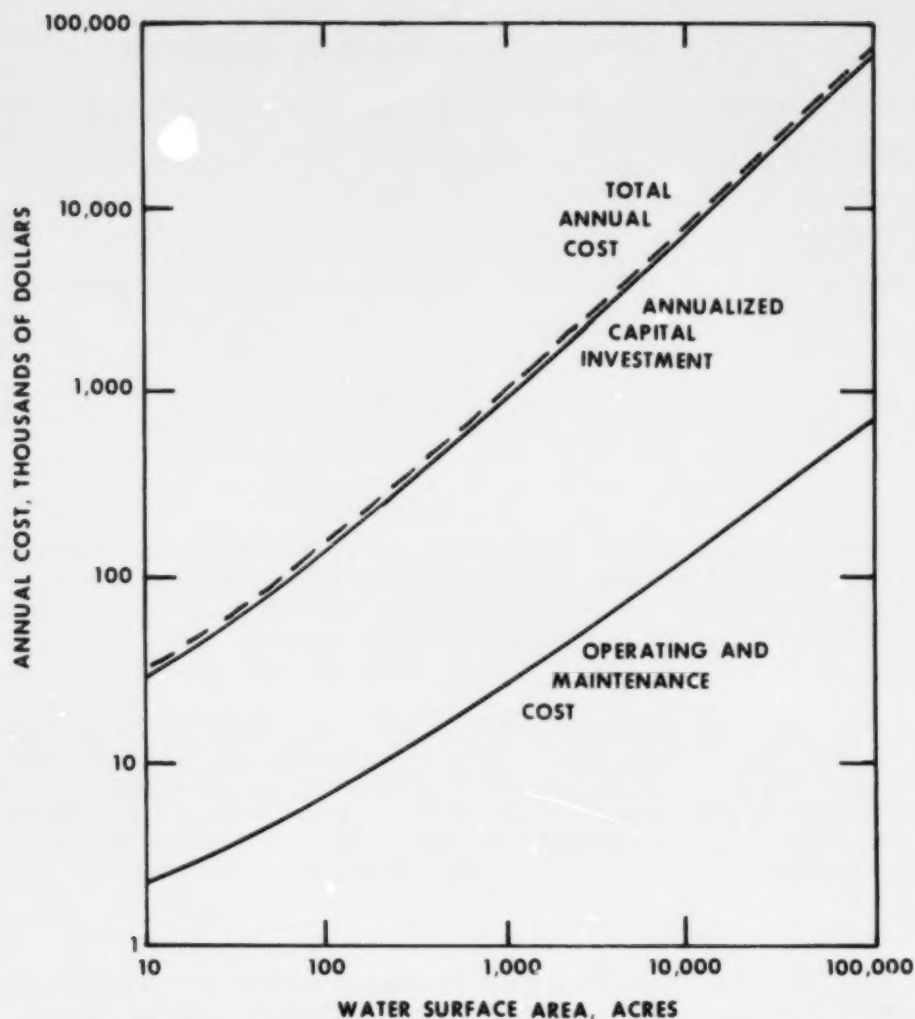


Figure 43. Total annual cost of evaporation ponds versus surface area.

Low rate systems are segmented into two types of application systems. Spray irrigation is defined as the controlled spraying of liquid onto the land at a rate measured in inches per week, with the flow path of the liquid being infiltration and percolation through the soil. Overland runoff is defined as the controlled discharge (by spraying or other means) of liquid onto the land at a rate measured in inches per week, with the flow path of the liquid being downslope across the land.

High rate systems consist of rapid infiltration, which is defined as the controlled discharge of liquid onto the land at a rate measured in feet per week, with the flow path being high rate infiltration and percolation through the soil.

The land area required for wastewater effluent disposal depends on the loading rate used. The loading rate in turn depends on many factors including:

- the soil capacity for infiltration and percolation;
- hydraulic conductivity (percolation capacity) of the root zone of cover vegetation;
- evapotranspiration capacity of site vegetation; and
- assimilation by soil and vegetation of nitrogen, phosphorus, suspended solids, BOD, heavy metals, and pathogenic organisms.

The maximum hydraulic loadings of wastewater for various soil textures is shown in Table 18.

TABLE 18. ESTIMATED MAXIMUM HYDRAULIC LOADING OF WASTEWATER EFFLUENT FOR VARIOUS SOIL TEXTURES (IDEAL CONDITIONS)

	Movement Through the Soil Root Zone*	
	cm/day	cm/yr
Fine sand	38.1	762
Sandy loam	19.0	457
Silt loam	8.9	229
Clay loam	3.8	102
Clay	1.3	25.4

*Precipitation plus effluent less evapotranspiration

The infiltration capacity of the soil limits the rate at which water can be applied to an area without runoff. Steeper slopes, previous erosion, and lack of dense vegetative cover also reduce the infiltration capacity and necessitate a corresponding reduction in application rates.

The hydraulic conductivity of the soil in a vertical direction determines the total precipitation and effluent application that can be transmitted to the ground water. Increased precipitation in a wet year reduces the amount of effluent which can be applied to various soil textures under ideal conditions.

Costs - The major advantage with wastewater land spreading is the low cost of the approach. Table 19 shows the total annualized cost of land spraying for the range of geothermal fluid flows anticipated. Capital investment costs and operating costs are based on an overland flow waste treatment system at Paris, Texas.⁷³ The system reported total construction costs at \$1170 per acre and operating costs at \$.052 per 1000 gallons

(\$0.014/1000 l) of wastewater. Application rate was a relatively high 0.6 inches (1.5 cm) per day. Compared to other land application methods (e.g., evaporation ponds), the cost for disposal of geothermal wastewaters is relatively low using the land spreading technique. However, a major disadvantage to this approach is that which confronts all land application approaches; namely, the vast amount of land required. For example, a typical size geothermal plant (e.g., 100,000 l/min) would require 5 square miles of land designated for waste disposal.

TABLE 19. ANNUAL COST OF DISPOSAL OF GEOTHERMAL WASTEWATERS BY LAND SPREADING

l/min	Land Surface Area Required, ^a Acres	Capital Investment, ^a \$1170/acre	Annualized Capital Cost 30 Years Life	Operating Cost @\$0.052/ 1000 gal. (\$0.014/1000l)	Total Annual Cost, \$
1,000	23.4	27,400	2,440	7,200	9,640
10,000	234	274,000	24,400	72,000	96,400
100,000	2,340	2,740,000	244,000	720,000	964,000
350,000	8,200	9,600,000	855,000	2,520,000	3,375,000

^aBased on application rate of .6 inches/day, (1.5 cm/day).

Containment of Unplanned Releases (Spills)

Methodology - Geothermal energy conversion systems will generally include the distribution of large volumes of geothermal fluids through a dispersed well and pipeline system. The possibility of system ruptures should be anticipated, and surface containment should be provided at points of high risk. Containment can include impermeable diking and/or excavation of areas large enough to contain the potential flow until the flow can be stopped.

Containment involves the routing of spills to a nearby holding basin, similar in design to an evaporation pond. Factors which will affect the design of the holding basin include: the availability of nearby land, the permeability of the soil and the ability of the environment to accept the spill without adverse effect, the presence of other lagoons or ponds already serving the plant, site topography, and geology. Generally, a holding basin will require construction to depths of 10 to 15 feet by forming an embankment with earth moving equipment.

Costs - The cost for construction of holding basins may be estimated using cost data for aerated stabilization ponds similar in design.⁷² The costs shown in Figure 44 are derived from these data. Costs are shown for surface containment ponds suitable to manage unplanned releases of geothermal fluids at various flows and durations. The surface area requirements for the

specified flow ranges (10 to 350,000 l/min.) vary from 12 square feet (1.1 m²) to 41 acres depending on the duration of the spill.

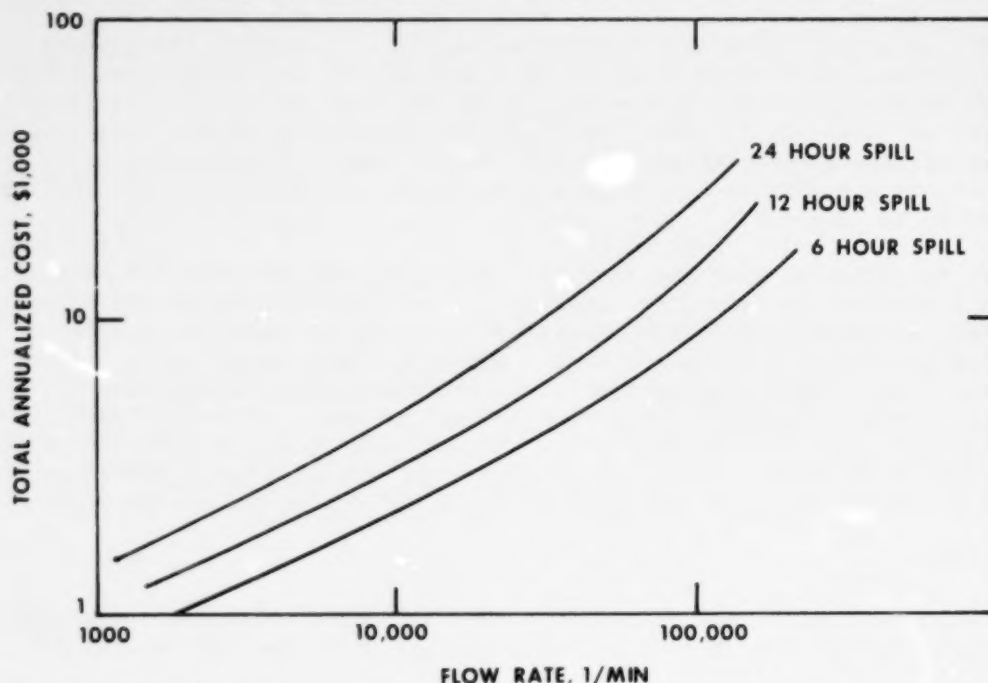


Figure 44. Annualized investment cost of spill containment ponds (10 foot depth)

SOLID WASTE DISPOSAL

In contrast to air and water treatment technologies with a diversity of options, solid waste disposal techniques are generally prescribed by regulations. The regulations usually require burial in a dry environment above and impermeably separated from the water table. Infiltration of runoff water must be prevented or confined. Clay, shale, or other low permeability formations around the disposal site cannot always be taken as a guarantee against infiltration and consequent leaching. If any parts of the waste are soluble and leaching does occur, the leachate must be confined and treated just as a liquid waste of similar composition. Solid wastes containing significant amounts of heavy metals and other substances considered "hazardous waste" are subject to special disposal regulations that may add to the disposal cost.

Treatment of geothermal wastes, particularly for removal of waterborne constituents, can produce very large quantities of sludge, including hazardous materials, depending of course upon the original concentration and the percentage removed. Materials added to facilitate treatment, particularly if not regenerated, can add substantially to the sludge quantity. Hydrogen sulfide removal from power generating facilities may typically generate several hundred metric tons of sludge per day. Removal of dissolved solids from high-salinity fluids may produce hundreds of thousands of metric tons per day.

The cost for disposal of hazardous waste in an appropriate landfill varies from \$8 to \$12 per ton of waste. This rate is independent of quantity accepted, although reduced rates up to 25% are available when disposal can be expected on a repetitive and high volume basis.⁷⁴ Normally, the greatest cost associated with waste disposal at a landfill is the hauling expenditure. Typical hauling rates are approximately \$32 per hour for a truck having a capacity of 20-25 metric tons. Hauling time consists of about 2 hours loading and unloading plus actual road-trip travel time. When hauling is to be conducted on a repetitive and high volume basis, charges to the user may be reduced by 10 to 25%.⁷⁴

It is estimated that the cost of sludge disposal would be \$21.40 per metric ton under the following conditions: hauling distance is 200 miles (322 km); disposal cost is \$10 per metric ton; and the cost of hauling is \$224 per truckload of 20 metric tons. Based on these costs, waste solids disposal from a high-salinity system, in which dissolved solids must be removed, would be prohibitive in most cases, and would be a very significant cost in any case. The disposal costs assumed here do not include the costs of sludge dewatering. The degree of dewatering required would depend on the economic tradeoff between wet transportation and drying before transport.

NOISE CONTROL

Noise from geothermal operations, as discussed previously, can be severe. Abatement technologies include prevention, shielding, and attenuation.⁷⁵

The greatest sources of noise are the escape of air during compressed air drilling, and the direct escape of raw geothermal fluid at wellheads, separators, and vents in the fluid distribution system. Secondary sources, such as those associated with a steam turbine generation plant and cooling tower, are significant, but are of far less off-site environmental significance.

A variety of silencers have been designed to attenuate noise from escaping air and fluid. They range from relatively crude rock-filled chambers, to baffled sound-absorbent mufflers, to large twin-cylinder centrifugal expansion towers. Two examples are shown in Figures 45 and 46. The type needed will depend upon the volume and nature of the escaping medium. For example, the large centrifugal type has generally been used for flashed-separated brine, whereas the smaller sound-absorbent type has been used for steam venting. At the wellhead, air or steam venting may be into a rock and water-filled pit. Most techniques are effective, but leave much room for improvement. Noise levels as high as 140 dB are typically reduced to 100 dB or less, by methods not necessarily expensive or complex. Attenuation can often be very effectively accomplished with very simple designs.

Noise from machinery operation can be reduced by applying state-of-the-art techniques such as shielding, baffling, vibration dampening, proper alignment, adequate lubrication, and other techniques, or by developing new technology.

Noise from permanent facilities can often be dampened by judicious placement, taking advantage of the absorbent properties of topography and various types of vegetation.

The costs of reducing noise are comparatively low, and in most cases, will not be significant in total operational costs.

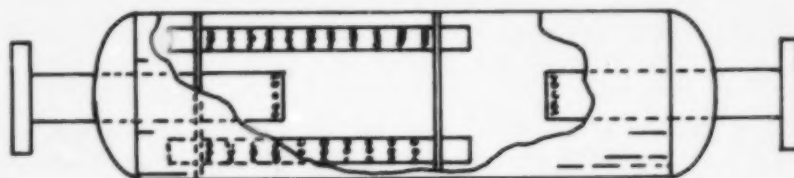


Figure 45. Typical multi-chamber silencer.

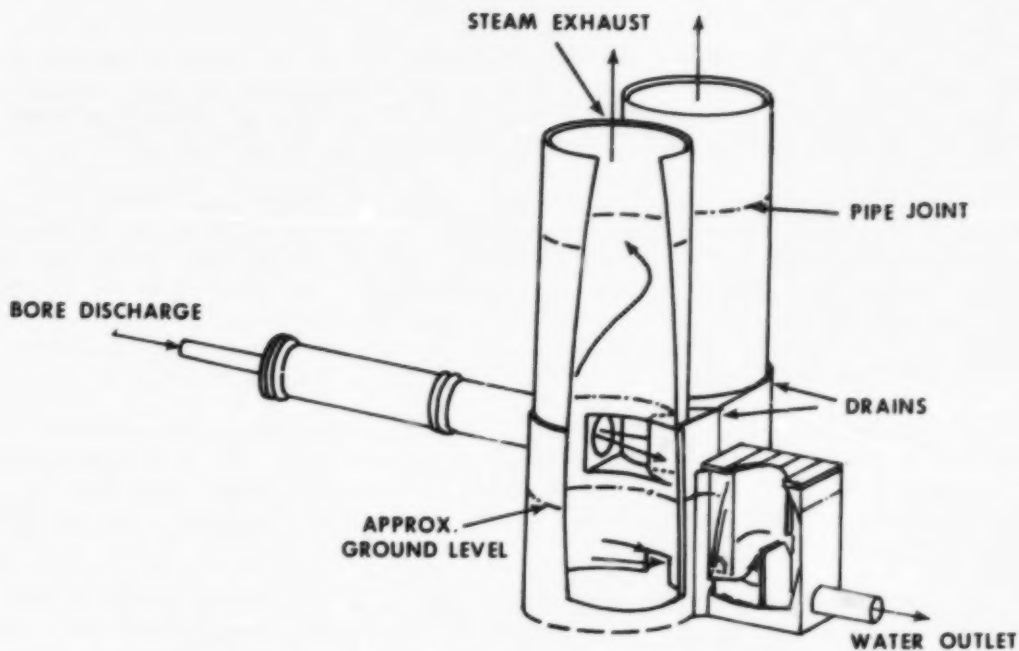


Figure 46. Twin-cylinder centrifugal expansion muffler for large volume fluid wasting. (Ref. 76)

VII. SUGGESTED POLLUTANT DISCHARGE LIMITS

GENERAL

The principal intent of this document is to provide pollution control guidance by way of suggested pollutant emission and discharge limitations, based upon an analysis of available data as presented herein. It must be emphasized again that the suggested limitations are not definitive, nor can they be until the character of the geothermal industry and associated technology is more firmly established with an adequate operational data base, including costs. Furthermore, health and environmental effects of many of the pollutants have not yet been adequately investigated. Such investigations will also have an impact on future limitations, most likely toward tightening of restrictions.

AIR POLLUTANT LIMITATIONS

Hydrogen Sulfide

Hydrogen sulfide is the only air pollutant from geothermal operations for which there is sufficient information to suggest emission limits. Several factors must be considered; these include existing ambient standards, health effects, range of concentrations in steam, and control technology.

Federal ambient air quality criteria do not include H_2S . California has imposed a State ambient standard of 0.03 ppm by volume as a 1-hour average, applicable state-wide. This state standard has had a profound effect at The Geysers in forcing control technology development. Not widely known is the fact that New Mexico has a standard of 0.003 ppm, one-tenth the concentration allowed in California. These state standards are based upon odor nuisance rather than health effects. The odor threshold is near 0.03 ppm.

As indicated in Section V, Table 8, H_2S at less than 1 ppm can have undesirable effects, although apparently it is not known to be a significant health hazard at that level. The current Occupational Safety and Health Administration regulations list an acceptable ceiling concentration of 20 ppm without respiratory protection.

According to the control technology information given in Section IV, about 90% H_2S removal is the most that can be expected from geothermal fluids, using available control processes. In the case of The Geysers this would be an emission average of 20 to 30 ppm, on a weight basis, of the total steam produced. This, of course, is not directly translated to an emission concentration, i.e., as an extreme, treatment of a stream of 100% H_2S might still

result in an emission of 100% H_2S , although the amount might be only one-tenth as much.

Emission limits must thus be in weight per unit of time, per unit of production, or per unit of raw fluid used. In geothermal electric production the obvious units are megawatt-hours or kilowatt-hours. If electricity production at The Geysers is taken as 80% of the 502 MW capacity, it produces an average of about 400 MW. If a produced H_2S rate of 812 kg/hr (1788 lb/hr) is assumed, then the raw load is about 2 kg/MWH, including pre-plant losses. Ninety percent reduction would result in an emission rate of 0.2 kg/MWH. Such a limitation assumes total H_2S control, from the wellhead through the power plant.

Emission and ambient concentrations are related but are not definitely correlatable. Calculating an emission rate based strictly upon an ambient standard at the property line or some other point is not possible now and would certainly be site-specific.

Based upon the assumptions that (1) The Geysers situation is typical with respect to hydrogen sulfide raw loadings, (2) 90% removal can be economically accomplished, and (3) adverse environmental effects will not occur with this degree of removal, it is suggested that emissions be limited to 10% of the loading in the raw geothermal fluid. Assuming that raw loadings will range up to twice those at The Geysers, it is expected that such a limit will be equivalent to an average between 0.2 and 0.4 kg/MWH of normal power generation (rated capacity X plant factor). For perspective, these figures, for a 100 MW capacity plant, translate to 16 to 32 kg/hr. Facilities producing raw loads less than 0.2 kg/MWH of normal power generation probably will not require treatment.

For non-electric uses, where H_2S may require control, loadings may be based upon raw fluid used as steam. Limits, comparable to those suggested for power generation, are suggested to be within the range of 20 to 40 kg/10⁶ kg steam used.

It is expected that environmental damage from hydrogen sulfide will not occur if the suggested limits are met. The ambient air limit at The Geysers is 0.03 ppm and is apparently met most of the time without treatment. Consistent 90% reduction should eliminate violations, particularly if individual sources remain dispersed.

Other Noncondensable Gases

Limitations are not suggested in this document for other noncondensable gases and metal vapors because as yet they have not been of proven concern, removal technologies have not been described, and effects have not been shown.

WATER POLLUTANT LIMITATIONS

By far the greatest volume of water in geothermal operations will be spent water variously contaminated by natural constituents from the geothermal reservoir. If the reservoir is dry steam-dominated, such as at The Geysers,

the liquid will be principally condensate, relatively clean and low in volume. However, dry steam reservoirs are rare; the great bulk of useful geothermal energy will be derived from water-dominated reservoirs. From these, large volumes of water will be withdrawn.

In suggesting pollutant limitations, the potential uses of geothermal energy are categorized into electric power generation and non-electric uses. The greatest rates of geothermal fluid withdrawal will be for power generation, where the fluids are also likely to be the hottest and the most contaminated. Non-electric applications, while they may be more numerous, will probably use lower temperature waters of lower chemical content.

Electric Power Generation

Two kinds of waste water will, in most cases, result from electric power generation. One is the residual water left after flashing or otherwise extracting the heat. The second type is cooling water and condensate. The cooling water may be from an external source; however, in most cases it is likely to be condensate recycled through cooling towers. In the latter case, the waste would be excess condensate and blowdown.

Residual geothermal liquid may contain heat and chemical constituents in quantities unacceptable for direct discharge to fresh waters. In a few cases, direct discharge to the ocean may be feasible where the waste characteristics are similar to sea water. Otherwise, treatment would be required for surface water discharges.

Alternative treatment technologies for geothermal brines were discussed in Section VI. They include evaporation ponds, forced evaporation and distillation, membrane filtration, and ion exchange. Except for totally contained evaporation ponds, which are taken to dryness, each of these technologies creates an even more concentrated brine residual that must be disposed of. At present, it does not appear that most of these technologies will be feasible for large volume treatment. Evaporation ponds may be, but very large areas would be required.

Subsurface injection of spent geothermal liquid to the producing reservoir now appears to be the most feasible disposal alternative. Because it has been demonstrated, and because it is considered necessary to minimize reservoir depletion and subsidence, injection is recommended.

Injection of excess condensate is also feasible and is recommended. It can be injected along with, and may in fact facilitate by dilution, spent brine injection.

The suggested maximum limitation therefore, for spent brine and cooling water from geothermal electric power generation, is no discharge to surface waters except where the discharge quality is equivalent to or exceeds that defined by receiving water quality standards for chemical constituents and radioactivity.

The no discharge limitation foresees subsurface injection in most cases. Thus, limitations must be established, in turn, for injection. Since it has the potential for contamination of ground waters used for other purposes, it is suggested that no change be allowed in the chemical or physical properties of waters outside the geothermal reservoir as a result of injection. This means injection in most cases to or below the geothermal reservoir. Ponding capability should be provided for containment of potential unplanned releases due to system failure.

Geopressured geothermal systems may not feasibly allow reinjection to the geothermal reservoir. In these cases injection to otherwise unusable saline aquifers at shallower levels may be allowed.

Non-electric Uses

Non-electric uses of geothermal energy, such as space heating, crop drying, soil heating, and spas, are expected to utilize relatively low-temperature sources since they do not require the high temperatures needed by thermodynamic cycles to obtain reasonable efficiencies. Low-temperature geothermal fluids are characteristically lower in chemical content. In many cases, they may be of lower salinity than surface waters in the vicinity. In fact, clean raw water may be required, especially in domestic uses where it has the potential to come into direct contact with the user.

Spent geothermal water after non-electric uses may often be directly discharged to surface waters without treatment. Cooling is part of the utilization process, so that additional cooling prior to discharge will probably not be required. Injection to the reservoir is recommended where surface water quality standards would be violated, or where the water may contain trace metals that might cause adverse effects (i.e., any heavy metal in concentrations above 1 mg/l is likely to cause concern). The need to inject to prevent depletion may not be required in most low-salinity reservoirs because they often may be sufficiently recharged by surface water percolation.

Where injection is carried out, prevention of ground water contamination is especially important, in some cases even within the geothermal reservoir. This is because the reservoir itself may be a source of potable water.

Suggested upper limits for surface water discharges from non-electric uses are equivalent to receiving water quality standards.

Sanitary Wastes and Construction Wastes

These wastes are typical of most industrial activities, including geothermal, and are subject to established sewage treatment and water quality standards attainable by conventional treatment technologies such as bio-oxidation and sedimentation. These technologies are routinely capable, if well-operated, of removing 90% of the raw pollutants.

LAND-DISPOSED WASTE LIMITATIONS

As discussed earlier, solid wastes are already subject to state regulation. Regulation is likely to soon become more restrictive under the newly enacted federal Resource Conservation and Recovery Act, particularly with respect to land-disposed toxic and hazardous materials.

Regulation of land-disposed waste generators, transporters, and disposal facilities may prescribe control methods that must be used. These methods will be applicable to geothermal land-disposed wastes such as drilling muds, well cuttings, and sludges resulting from treatment of gases and liquids, as well as surface impoundments of potentially hazardous wastes. Permanent exclusion and perpetual maintenance of disposal sites may be needed after plant de-commissioning.

The suggested limitations for geothermal solid wastes are total confinement and no significant emissions or discharges therefrom to the air, surface water or ground water. Wherever it is not possible to permanently contain the leachate, it must be further treated for removal of any contaminant that would have an adverse impact.

NOISE LIMITATIONS

The information on noise and its effects, as presented in this document, is not sufficient to independently suggest limitations for geothermal operations. It is therefore suggested that limitations, similar to the U.S. Geological Survey regulations currently imposed on Federal lands be observed as a minimum at all sites. Thus the suggested limitation is 65 dBA at the property line or at a distance of one-half mile from the source, whichever is greater. Several states have more restrictive limitations, and these should be observed. Regulations of the Occupational Safety and Health Administration limit noise, without ear protection, to a daily limit of 90 dBA for eight hours and 115 dBA for 15 minutes.

As indicated in the previous section, noise suppression technology for geothermal applications has not received a great deal of attention and can probably be improved significantly at relatively small cost. This in turn indicates that noise limits might become more restrictive in the future.

VIII. FUTURE DEVELOPMENT OF EFFLUENT AND EMISSION STANDARDS

As indicated throughout this document, pollution control for the geothermal industry, during its development stages and later full-scale commercialization, will be regulated by discharge and disposal permits. The permit systems will be implemented and principally administered by the States under approval by the Administrator of the U. S. Environmental Protection Agency. On Federal lands the U. S. Geological Survey supervises geothermal operations and issues operational permits. It also monitors operations for regulatory compliance, including pollution control. The USGS interface with other agencies in the area of pollution control has not yet been clearly defined.

During the development stages, permits are likely to be issued on a case-by-case basis, with discharge loadings based upon the maintenance of ambient standards. Later permits, during established commercialization, may restrict loadings based upon water Effluent Guidelines and air New Source Performance Standards. These guidelines and standards would, in turn, be based upon concurrent pollution control and conversion process technology development during the pre-commercial stages.

Effluent Guidelines and New Source Performance Standards must be founded upon demonstrated control technology. The geothermal industry and its regulation are unique in that the industry is just beginning, and the inertial resistance characteristic of established industries toward pollution control, created by past less restrictive requirements, is virtually nonexistent. The principal geothermal industrial development agency, the U. S. Department of Energy, is committed by law to concurrently develop pollution control technology. Thus, in the case of geothermal development the heretofore rare opportunity exists to create an industry with integral pollution control from the outset.

Effluent Guidelines and New Source Performance Standards are normally based upon demonstrated achievable pollutant control technology. In some cases, this may not effect the achievement of ambient standards. Thus, ambient standards in the development stage may be useful in forcing the development of improved, economically viable control technology where required.

Geothermal pollution control research, development, and demonstration costs will be largely borne by government prior to large private investment. The result should be that the geothermal industry will find itself, when it is ready to become fully operational, in the advantageous position of having pollution control limits and technology that are available and compatible. Ideally, the application of control technology then would result in no

ambient standards violations in any case. This would increase industry's confidence in its ability to develop within the limits of environmental regulation.

The evolution of pollution control standards by EPA should be a cooperative process involving inputs principally from the Department of Energy, the U. S. Geological Survey, the States, and private developers. It must include a free exchange of information among all interested parties. The principal contributions of each are suggested as follows, with the most significant underlined:

- Environmental Protection Agency

- Overview of environmental and health research and development by other agencies and the industry.
- Characterization and evaluation of pollutants.
- Evaluation of pollutant environmental and health effects.
- Regionwide pollution monitoring.
- Guidance as to limitations based upon effects.
- Evaluation of control systems and suggestions for improvements.
- Development of new water quality criteria.
- Support of pollution control research and development.
- Development of pollution control regulations and promulgation of Effluent Guidelines, New Source Performance Standards, reinjection regulations, solid waste regulations, and guidance to states on permitting programs.

- Department of Energy

- Design, construction, and operation of pollution control systems.
- Conduct and support of control technology research, development, and demonstration.
- On-site environmental baseline characterization.
- Initial effluent characterization and evaluation of effects.
- Establishment and maintenance of liaison with all developers.
- Input to pollution control regulations development.

- U. S. Geological Survey
 - Assurance of compliance with pollution limitations on Federal lands.
 - Development of resource characterization data.
 - Establishment of environmental regulations on federal lands where otherwise lacking.
 - Input to pollution control regulations development.
- States (regulatory and development agencies)
 - Implementation of interim pollution Control program by permit and monitoring systems.
 - Support of baseline monitoring.
 - Statewide water and air quality monitoring and planning.
 - Input to pollution control regulation development.
- Private developers
 - Design, construction, and operation of pollution control systems to meet established and/or anticipated pollution control limits.
 - Monitoring of effluents and emissions throughout development and operation.
 - Evaluation of pollution control systems.
 - Environmental baseline characterization.
 - Input to pollution control regulations development.

IX. EFFLUENT AND EMISSION MONITORING

Monitoring as described here is primarily for the purpose of determining the quantity of pollutants discharged to the air, surface water, and ground water. As such, monitoring must include sampling and analysis for contaminants at effluent and emission points. These measurements will be required as a part of permit conditions to ensure that permitted loading limits are in fact met.

Pollutant loading limitations may be based, as discussed earlier, upon effluent and emission standards when such are developed. In the interim, those limitations will be based upon calculations and judgments, by the permitting agency, as to loadings that will allow ambient air and water standards to be met. Also as discussed earlier, ambient standards may control limitations even after the development of effluent and emission standards, where the latter would allow ambient standards to be violated. Thus, ambient monitoring at receptor points will also be required, in most cases, in addition to effluent and emission monitoring.

This document suggests pollutant monitoring locations and frequencies. It does not describe actual sampling and analytical techniques. It recognizes that initial monitoring may be more cumbersome until the industry and a data base have been sufficiently developed, and until geothermal specific monitoring methodologies have been developed. EPA's Environmental Monitoring and Support Laboratory-Las Vegas is currently engaged in methodology development.

AIR AND WATER POINT SOURCE MONITORING

Any planned waste liquid discharges or gas emissions resulting from materials used in the geothermal energy conversion process must be monitored by the operator in accordance with permit requirements. For liquid discharges, the required measurements may include volume, selected chemical constituents, suspended solids, temperature, pH, and radioactivity. Gas emission measurements will include volume and concentrations of regulated constituents such as hydrogen sulfide. Radiological analysis may be required. Any or all of the pollutants listed in Sections IV and V may require measurement.

Some planned direct discharges and emissions are likely to be intermittent, such as at wellheads, vents, and bypasses, while others may be continuous, such as at separators, mufflers, scrubbers, gas ejectors, cooling towers, and spent liquid drains. It is anticipated that, on the whole, continuous discharges, where permitted, will greatly exceed intermittent discharges in volume.

Monitoring of wastewater surface discharges and gas emissions should be conducted at each planned discharge site at a frequency commensurate with the character of discharge, e.g. less frequently for discharges of uniform character. Often, liquid effluents and gases will be combined and can be sampled simultaneously.

The frequency, duration, and method of sampling should be such that a calculated average constituent loading $\pm$ 50% will encompass the true average loading over any period of time.

In most cases, it is expected that discharges and emissions will be fairly uniform to the extent that they result from fluid consistently withdrawn from the geothermal reservoir. This would suggest that high frequency sampling is probably not demanded. The sampling frequency for continuous discharges might reasonably be monthly, with a sampling duration of 24 hours. For treated effluents and emissions, where treatment may not provide consistently predictable results, the required frequency may be weekly or more often. Planned, intermittent, direct discharges, where the content and volume are not known prior to release, should be sampled whenever they occur, for a duration proportional to that for continuous discharges, perhaps 1/7 to 1/30 of the total discharge time.

All discharge permits will require that monitoring be done by the operator, that records of measurements be maintained for inspection by the regulatory agency, that loading data for all releases be submitted periodically to the regulatory agency and that standard violations be reported. The regulatory agency may sample discharges to confirm operator monitoring results and to determine permit compliance.

AMBIENT AIR MONITORING

An initial ambient air sampling and analysis program should be established by the geothermal operator for all geothermal energy conversion facilities which require emission monitoring. Such a program can be expected to last at least until data accumulation is sufficient to show that ambient air quality standards are not violated or adverse impacts do not occur as a result of the emissions.

Ambient air monitoring should be designed on a case-by-case basis to ensure receptor protection (or to detect standards violations) at the facility's boundary with other private or public property or even within its boundaries if the property is accessible for public use. Monitoring sites should be selected to conform with principal directions of pollutant transport by increased sampling frequencies at those points.

Ambient monitoring sites should be established on the basis of a prior continuous sampling program at all compass octants from the production facilities or the geographic center of the production field. Sites should be at distances from the source(s) sufficient to delineate pollutant dispersion characteristics and to encompass any area where concentrations above ambient may be caused by such source(s). The continuous sampling program should be of sufficient duration to include characteristic weather variations throughout

the year. Sampling should be done within 5 meters (15 feet) of ground level, so that concentrations may be related to terrestrial receptor effects.

Where patterns are developed by the continuous sampling program, the same stations may be used for monitoring, with the sampling frequencies ascertained from an analysis of the concentrations vs. time distributions. The monitoring program might thus lie somewhere between the extremes of continuous sampling at all stations to no sampling at any stations. The latter would not be expected in most cases.

Any ambient air monitoring program will likely be subject to criticism, periodic reevaluation, and redesign to conform to expanded or reduced production or to natural factors not known at the time of program establishment. This may be particularly true for larger and expanding production facilities and/or those with relatively high non-condensable gas fractions in the raw geothermal fluid.

AMBIENT WATER MONITORING

In the past, it has been common to require industries to monitor discharges, but not surface receiving water quality. The bulk of those measurements have been made by regulatory agencies. Permits may require geothermal developers to monitor ambient water quality. Even if ambient monitoring is not required, voluntary monitoring will likely be to their advantage, particularly if discharge loading limitations are based upon water quality standards. Limitations, thus developed, are intended to prevent violations of concentration limits within the receiving waters under all flow conditions.

Monitoring points should be selected to ensure, as a minimum, that the quality of surface water be monitored where it is accessible to the use of others. In many cases, this may be at the downstream point of intersection of the developer's property line and surface drainage. However if the developer's property is leased public land, water quality and thus monitoring stations may be maintained within the leasehold, since all but operationally unsafe areas may still be publicly accessible.

Surface water quality monitoring may be required even if there are no planned surface water discharges. One of the reasons for this is air pollutants from geothermal operations may result in atmospheric "fallout" contamination. Another is that, if surface containment is employed, leakage may occur.

Water quality monitoring should include the same constituents and properties for which effluents are monitored.

The locations, frequency, and duration of surface water ambient monitoring should be determined after consideration of several factors such as:

- size, flow, and flow variability of the receiving water body
- stream mixing characteristics

- volume of the discharge
- chemical and physical characteristics of the discharge and the consistency thereof
- waste water treatment system characteristics
- air emission characteristics
- downstream water uses
- upstream pollutional discharges
- stream ecology

Despite the apparent complexity of the monitoring selection process, the resulting monitoring scheme would be expected to be relatively simple. One extreme might be represented by a uniformly low volume, low salinity discharge into a large flowing stream. Monitoring then might be one grab sample upstream and one downstream taken monthly at points of well-mixed stream flow. The other extreme might be represented by a high volume, high salinity, relatively nonuniform discharge into a low or variably flowing stream already contaminated by upstream users. In this case, much more frequent monitoring might be required at several upstream and downstream stations. Several cross-sectional grab samples might be taken, flows measured, and data composited. In addition to determining constituent concentrations, effluent loadings may be confirmed.

Frequency of ambient water monitoring should be commensurate with variability in effluent characteristics and stream flow. However, it appears likely that in most cases, monthly sampling might be acceptable, because of the expected uniformity of discharge characteristics.

GROUND WATER MONITORING

Spent fluid is likely to be injected in many, if not most, cases to or below the geothermal reservoir to alleviate reservoir depletion and subsidence. Injection is also likely to be the most environmentally acceptable disposal method for high salinity fluids, if performed properly.

Subsurface injection may be the disposal method of choice, even if spent fluid cannot be feasibly returned to the geothermal reservoir. This is the case in known geopressured areas, where injection would probably be to shallower aquifers with similar chemical characteristics.

Injection in any case will have the potential, as a result of unplanned or accidental system disruption, of contaminating aquifers usable for other purposes, such as drinking water. Such contamination could have the most serious consequences. If such contamination occurs, it may be difficult, if not impossible, to return the aquifer to its original condition. Careful monitoring may be the only way to ensure that significant contamination does not occur with injection.

Because of the serious nature of potential ground water contamination, the Environmental Protection Agency is currently conducting a study to design an adequate ground water monitoring methodology for geothermal operations. Many other studies of geology, hydrology, scaling and corrosion, reservoir dynamics, etc. by other agencies will have direct bearing on injection technology and, in turn, monitoring methodology. Until monitoring methodologies are fully developed, interim requirements will necessarily be imposed, based upon state-of-the-art injection technologies.

The ground water chemical characteristics of all aquifers overlying the geothermal reservoir should be monitored. The monitored constituents should include all those that would be measured if the waste water were surface-discharged, and perhaps others, if chemicals are added to promote injection.

Methods, principally electro-chemical, are being researched to monitor by injection well instrumentation, the location and extent of migration of injected fluids. Until such methods are perfected, monitoring may require sampling from wells into each aquifer. Sampling, by fluid retrieval, of multiple aquifers from one well should not be encouraged because of potential mixing. Sampling wells should surround the geothermal operation, and all should be located within a few hundred yards of reinjection wells. The capability should exist to sample each aquifer at two or more points down-gradient from principal injection wells. Existing water supply wells may be used where determined appropriate.

The frequency of ground water aquifer sampling will depend principally upon the rate of injection and the quality characteristics of the injected fluid vs. those of the aquifer. Higher injection rates of more saline brines would probably demand higher frequency sampling than lower injection rates of "cleaner" fluids. In most cases, however, it is expected that a 30-day sampling frequency will be near the optimum. Various characteristics may demand more frequent sampling.

Simple grab samples should be sufficient for ground water monitoring.

LAND-DISPOSED WASTES

Land-disposed wastes requiring control by isolation are determined by chemical characterization. Monitoring of storage, treatment, and disposal sites under control of the geothermal operator will be required under State and Federal regulations to determine whether any constituents escape by leaching or percolation to surface and/or ground water. Monitoring requirements will be similar to those described above for ambient surface waters and for ground water. The most significant difference is that probably only the uppermost ground water aquifer may need to be monitored.

NOISE MONITORING

Monitoring of noise is accomplished by noise measurements at the property line or the boundary with other use areas, at points nearest the noise source. It is probable that a set monitoring schedule need not be established. Rather, measurements should be made upon a change in type or mode of operation.

Measurement methodologies have been developed for many specific noise sources and can be integrated to measure overall noise at the boundary site.

A noise monitoring program should be established by the operator to assure himself that violations of local, State and Federal regulations do not occur. Because noise cannot be ignored, it may be monitored frequently by regulatory agencies.

BASELINE AIR AND WATER MONITORING

Prior to geothermal energy production, the existing state and natural variations of air and water quality should be determined in detail by the developer in accord with the needs of regulating agencies. Baseline descriptions are in fact part of the requirement for environmental impact reports and analyses, which in turn are required for all projects on Federal lands and most on state lands. Baseline assessment may require long-term, detailed measurements to establish the basis for differentiating natural and operation-caused changes.

The U. S. Department of Interior's Geothermal Environmental Advisory Panel (GEAP) has prepared a document entitled "Guidelines for Acquiring Environmental Baseline Data on Federal Geothermal Leases."⁷⁷ The document describes procedures for gathering chemical, physical and biological data for a one-year period prior to submission of a plan for production, as required by the Geothermal Steam Act of 1970. The data are submitted to the U. S. Geological Survey Area Geothermal Supervisor, who may alter the requirements according to specific needs.

The Department of Energy, Division of Geothermal Energy has developed general requirements for describing baseline data acquisition and evaluation methodology in environmental reports on DOE-sponsored geothermal activities.⁷⁸ The U. S. Fish and Wildlife Service has prepared a handbook for gathering and assessing biological data, and for mitigating impacts.⁷⁹ Each of the sources of information should be used by the developer in setting up a baseline monitoring program.

Baseline water and air quality monitoring should be viewed as setting the stage for later ambient monitoring during full-scale operations. Thus, it should include measurements of the same constituents that will be monitored later during construction and operation of the energy conversion facility. With this view in mind, it would be expected that the operational monitoring would utilize baseline stations established earlier. This of course requires coordinated planning throughout development.

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APPENDIX

SUMMARY OF LAWS REQUIRING OR RELATED TO GEOTHERMAL POLLUTION CONTROL

Federal Pollution Control Laws Administered by the Environmental Protection Agency

Any geothermal energy development is subject to many pollution control laws and regulations. The most significant of the federal laws, which apply to all industrial development, are:

- (1) the Federal Water Pollution Control Act Amendments of 1972 (PL 92-500);
- (2) the Clean Air Act as amended (PL 91-604 and PL 95-95),
- (3) the Safe Drinking Water Act (PL 93-523);
- (4) the Resource Conservation and Recovery Act of 1976 (PL 94-580);
- (5) the Noise Control Act of 1972 (PL 92-574); and
- (6) the Toxic Substances Control Act (PL 94-469).

All but the last of the above federal laws allows and fosters delegation of authority to the states upon their meeting certain requirements. In effect, the federal laws extend down through state, regional, and local levels.

Federal Water Pollution Control Act Amendments (FWPCA) of 1972

Several sections of this Act apply to geothermal development. Probably the most significant sections are in Title III - Standards and Enforcement. Section 301 calls for the application of "best practicable control technology currently available" by July 1, 1977, for point sources other than publicly owned treatment works. This section further calls for the application of "best available technology economically achievable" by July 1, 1983. This section further requires the elimination of all pollutants where technologically and economically achievable. Section 304 calls for the definition by the EPA of such technologies, and effluent limits attainable thereby, through the issuance of "Effluent Guidelines" regulations. For the geothermal energy industry, those regulations have not yet been developed and are not currently scheduled. However, such regulations may be expected when the industry is firmly established and technologies have been demonstrated. Effluent

guidelines are promulgated, upon development, as regulations in 40 CFR Parts 402 through 699.

Section 303 of the FWPCA calls for the establishment and maintenance of receiving water quality standards for both interstate and intrastate surface waters. Such standards have been established by the States and approved by the Administrator (40 CFR Part 120). They are subject to periodic revision. The provisions of this section interact with those of Section 301 and prevail in establishing permit limitations where the application of Effluent Guidelines limits is not sufficient to meet receiving water quality standards. This is likely to be the case in many, if not most, areas of early geothermal energy development.

Section 306 of the FWPCA calls for the establishment of "national standards of performance" for new sources of water pollution after the EPA Administrator publishes a list of such sources. Past development of such standards indicates that they would be similar to "best available technology economically achievable." There is currently no schedule for establishing new source performance standards for the geothermal industry but they also can be expected in the future. New source performance standards are promulgated along with effluent guidelines in 40 CFR Parts 402 through 699.

Section 307 of the FWPCA calls specifically for the identification of toxic pollutants and the establishment of effluent standards, regardless of the source, for such pollutants. Standards were proposed in 1973 for nine substances. Final regulations were published in January and February 1977 for six substances: aldrin/dieldrin, benzidine, DDT (DDD, DDE), endrin, PCB and toxaphene. These regulations have been promulgated in 40 CFR Part 129. Since such materials are not in geothermal fluids they have no bearing on the development of geothermal energy. Any toxic substance limitations applicable to geothermal development are likely to be established by effluent guidelines (Sections 301 and 304) and water quality standards (Section 303).

The implementation of effluent guidelines and water quality standards is carried out under authority of Section 402 of the FWPCA by way of the "National Pollutant Discharge Elimination System" (NPDES). This requires a discharge permit based upon Effluent Guidelines and/or Water Quality Standards for any point source discharge to surface drainage. Permitting authority has been delegated to those States which have met implementation program requirements. Implementing regulations have been published in 40 CFR Part 125.

Section 308 of the FWPCA requires dischargers regulated by the Act to sample and maintain records of discharge loadings and make them available to authorized federal and state regulatory personnel. It also authorizes right of entry to the discharger's premises by those personnel. The recorded data must be gathered and maintained as prescribed in permit conditions, and may be used as evidence in enforcement of pollutant limitations.

Clean Air Act as Amended

The Clean Air Act also has several sections which may significantly affect geothermal energy development.

Section 107 of the Clean Air Act allows and provides for the establishment of intrastate and interstate Air Quality Control Regions in which the states must provide implementation plans under Section 110 for assuring air quality.

Under Section 108 of the Clean Air Act and Section 106 of the 1977 amendments, the Administrator of the Environmental Protection Agency may publish air quality criteria. Based upon the criteria, he then publishes national primary (to protect public health) and secondary (to protect public welfare) ambient air quality standards (Section 109 of the Clean Air Act) for pollutants determined to have adverse effects. National air quality standards have thus far been established for six pollutants: particulates, sulfur dioxide, nitrogen oxides, hydrocarbons, photochemical oxidants, and carbon monoxide (40 CFR Part 50). Lead may be added in the near future. The states must establish implementation plans (Section 110 of the Clean Air Act), including emission limits, first to meet primary standards and later to meet secondary standards, in each Air Quality Control Region. These plans are approved by the Administrator and promulgated in 40 CFR Part 52. Since the listed pollutants may not be significant in most geothermal sources, the importance of current ambient standards may not be great. However, the states may unilaterally include other constituents, and some have done so, e.g., hydrogen sulfide in California.

Section 111 of the Clean Air Act and Section 109 of the 1977 amendments allow the Administrator of the Environmental Protection Agency to establish New Source Performance Standards for air pollutants from stationary source categories. Once established, these standards become applicable to all new sources in such a category, and further, the States must then establish emission limits for the same constituents from existing sources within that category. This is likely to be the principal route for federal regulation of air emissions, although such standards have not been developed yet for the geothermal industry. New Source Performance Standards are based upon best demonstrated economically achievable emission reduction, similar to the basis for water discharge National Standards of Performance. They are published as regulations in 40 CFR Part 60.

Section 112 of the Clean Air Act and Section 110 of the 1977 amendments provide for the establishment of emission standards for hazardous air pollutants from stationary sources. Such standards are based upon a determination that a pollutant causes or contributes to an increase in mortality or serious illness in humans. Thus far, standards have been established for specific sources of mercury, asbestos, beryllium and vinyl chloride (40 CFR Part 61). These standards do not apply to geothermal sources. However, geothermal sources may in some cases contain hazardous air pollutants, leaving open the possibility that such standards may be developed. The proof-of-harm requirement may make such development very difficult.

Section 122 of the Clean Air Act Amendments of 1977 provides for the regulation of emissions of radioactive substances, cadmium and arsenic, all of which may be found in geothermal fluids.

Safe Drinking Water Act

This Act is administered by the Environmental Protection Agency and allows and provides for State implementation of its provisions. Part C of the Act, "Protection of Underground Sources of Drinking Water," is of greatest significance to geothermal energy development in that it requires the promulgation of regulations to control underground injection. ReInjection is an integral part of most existing and proposed geothermal development. Regulations under this Act have been proposed (40 CFR 146), but their applicability to geothermal operations has not yet been established. Any regulations may be further extended by more restrictive state regulations. ReInjection permits will be required, as they already are in most states, the issuance of which is likely to be based upon an analysis of geological, hydrological, and injection system design and operational information.

Under the Geothermal Steam Act of 1970, the U. S. Geological Survey has issued Geothermal Resources Operational Orders, which include specific requirements for reInjection wells on Federal lands. Regulations which may be developed under the Safe Drinking Water Act for reInjection are not likely to be in conflict with the Operational Orders.

The Environmental Protection Agency already has some control over underground injection via NPDES permits using Administrative Order No. 5, which provides for approval of injection systems that are part of any other project subject to EPA regulation.

Resource Conservation and Recovery Act of 1976

The provisions of this Act, administered by the Environmental Protection Agency, are principally concerned with solid wastes. Subpart C - Hazardous Waste Management, important to geothermal energy development, involves regulatory control of storage, treatment, and disposal of potentially hazardous wastes in landfills and surface impoundments. The potentially hazardous wastes may be liquid, solid, or a combination. Wastes considered potentially hazardous are those which may cause or contribute to adverse effects on human health or the environment when not properly controlled. Regulations to be developed under the Act are likely to have significant ramifications for the geothermal industry in those cases where spent brine surface impoundments are used and where waste sludges are created, such as in the treatment of waters and noncondensable gases.

Section 3001 calls for the Administrator to identify and list hazardous wastes in conformance with criteria he must first establish.

Sections 3002, 3003, and 3004 require the establishment of standards for the identified hazardous wastes applicable to waste generators, transporters, and disposal operators, respectively. Complete traceable records are to be a principal feature of the regulations. Geothermal developers may be subject to all three sets of regulations.

Section 3005 requires permits for hazardous waste disposal facilities, with permits to be approved when certain conditions are met. Section 3006 authorizes the states to administer and enforce hazardous waste programs upon approval by the Administrator.

Section 3007 authorizes access to any facility handling hazardous wastes and to its records for regulatory development and enforcement purposes.

Regulations have not yet been developed under any sections of the Resource Conservation and Recovery Act, although they are imminent.

Toxic Substances Control Act

This Act is aimed principally at manufacturers and distributors of toxic chemicals, in order to control indiscriminate proliferation of such materials in the environment. The provisions of the Act can conceivably apply to minerals which might be commercially produced from geothermal development.

Section 4 may require testing by the producer to determine health and environmental effects and the degree of risk. Testing will be done in accordance with standards to be promulgated.

Section 5 requires notice of intent and submission of test data prior to manufacture of new chemicals.

Under Section 6, the Administrator may prohibit the manufacture or distribution of chemical substances if he determines that such substances present an unreasonable risk.

Section 8 requires maintenance of records and authorizes official access to such records.

The Toxic Substances Control Act, unlike the others thus far described, does not provide for State control of the program, but does allow states to apply rules not in conflict with the Act.

Noise Control Act of 1972

This Act contains broad noise control provisions for regulating and labeling products, many of which are used at geothermal facilities. In addition, EPA has been given coordination authority of all programs of other Federal agencies relating to noise research and noise control. It has also been given authority to insure that all Federal facilities comply with appropriate Federal, State, and local noise regulations. Many states and local communities regulate noise, and the U. S. Geological Survey has noise regulations (in Geothermal Resources Operational Order 4) for developers on leased Federal lands.

Other Federal Laws Requiring or
Related to Geothermal Pollution Control

Pollution control considerations have been included in several other laws affecting geothermal energy development. These laws are aimed principally at (1) broad-scale encouragement of energy resource development or (2) broad-scale protection of environmental values. The most significant of the first type are the following:

- Geothermal Steam Act of 1970
- Federal Nonnuclear Energy Research and Development Act of 1974
- Geothermal Energy Research and Development Act of 1974

The second type includes:

- National Environmental Policy Act of 1969
- Fish and Wildlife Coordination Act
- Endangered Species Act of 1973
- Wilderness Act
- Marine Protection, Research and Sanctuaries Act of 1972

Geothermal Steam Act of 1970

This Act is one of the most significant laws affecting the pace and direction of geothermal energy development. It essentially controls leasing of federal lands and all phases of post-lease operations on those lands; those lands include a large number of the known geothermal resource areas (KGRA's). The Department of the Interior, Bureau of Land Management, administers pre-lease and leasing requirements. The Department of the Interior, U. S. Geological Survey, administers post-lease requirements, through an "Area Geothermal Supervisor." Currently there is only one Area Geothermal Supervisor with broad responsibilities over most activities including those that result in air and water pollution.

On other than Federal lands, State and local regulations have generally been patterned after those of the Geothermal Steam Act.

The protection of the environment through regulation is provided for in Section 24 of the Geothermal Steam Act. Regulations have been published in 30 CFR 270, under which the Area Geothermal Supervisor operates. Environmental provisions require preproduction studies, for at least one year, of air and water quality, noise and ecological systems. In addition, the regulations require compliance with all federal and state standards for air, water, land, and noise pollution. Geothermal Resource Operational Orders (GRO) are issued by the Area Geothermal Supervisor to implement the regulations. The principal set of environmental requirements is contained in GRO

Order 4, which requires conformance with all federal and state air and water pollution control standards, and establish detailed noise standards.

Federal Nonnuclear Energy Research and Development Act of 1974

This is the Act which mandated the activities of the Energy Research and Development Administration (ERDA). One of those activities is the active encouragement of geothermal energy technology development through commercial demonstration. The Act (Section 6(b)(3)(K)) also provides for the acceleration of the commercial demonstration of environmental control systems for energy technologies. The objectives are restated in several problem definition and planning reports prepared by ERDA.

Geothermal Energy Research and Development Act of 1974

This Act authorizes and defines more specifically the responsibilities of the federal government, through the direction of ERDA, in developing and demonstrating the commercial viability of geothermal energy conversion. The objectives of the Act are to be accomplished in concert with private developers through grants, contracts, and loan guarantees.

This Act includes a requirement for the development of environmentally acceptable processes (Section 2(12)). More specifically, Section 104 requires that the geothermal research and development program develop and evaluate improved waste control, disposal and monitoring methods; evaluate environmental effects of geothermal development; improve impact assessment procedures; prepare environmental impact statements; and assure compliance with standards and criteria. Meeting environmental standards is one of the specific goals of the demonstration program (Section 105(a)(1)). Section 301 of the Act requires particular emphasis of all participants upon protection of the environment and safety.

National Environmental Policy Act of 1969

This Act has had profound effects in calling public attention to the environmental consequences of major new projects. Section 102 of the Act requires an environmental impact statement for all major federal actions affecting the quality of the human environment. The Act produced a ripple effect in that most states have similar laws for state actions. In most cases of major development, an environmental impact statement can be anticipated at some stage prior to commercial energy production, whether it is on federal, state, or private land.

The environmental impact statement requirements at the federal level are applicable to geothermal development on federal lands and to any government-supported research and demonstration projects. In many cases, an initial environmental assessment report may indicate that the action is sufficiently significant to require a full impact statement.

The impact statement must describe adverse impacts, including those caused by any kind of pollution, on society and its environment. It also must discuss alternatives to the proposed development and their consequences,

and must describe irretrievable resource commitments. Details on the materials to be included have been published as regulations by several federal agencies. Examples of these are the general guidelines published by the Council on Environmental Quality (40 CFR 1500) and the more specific guidelines of ERDA for its projects (10 CFR 711). ERDA has recently published "Guidelines to the Preparation of Environmental Reports for Geothermal Development Projects," which outline in detail the material to be included. Further useful information may be found in "Geothermal Handbook" prepared by the U. S. Fish and Wildlife Service.

Environmental impact statements often require detailed field and analytical work and result in long comprehensive reports.

Fish and Wildlife Coordination Act; Endangered Species Act; Wilderness Act; and Marine Protection, Research and Sanctuaries Act

These federal laws do not directly address pollution control and its requirements. Instead they allow for prohibition of or advisory action against certain activities in the interest of preserving wildlife habitats and esthetic values. They also may allow for or require mitigating measures where harm may occur.

State and Local Pollution Control Laws and Regulations

It is not the intent of this document to detail the pollution control laws and regulations of the various state and local governments. Suffice it to say that most of these regulations are intimately tied to the implementation of federal regulations, generally by authority delegated to the states by the EPA Administrator. Generally, where the EPA Administrator feels that such delegated authority is not being implemented satisfactorily, he may retrieve or retain that authority. It is important to note that state and local regulations may impose restrictions on pollution discharges and emissions beyond those required by federal law, but may not be less restrictive.

Thus far, because federal laws are relatively weak, state and local regulations have dominated in control of (1) solid wastes and (2) noise from stationary sources. The degree of federal influence (with state implementation) will sharply increase in the area of solid wastes under the new Resource Conservation and Recovery Act of 1976. The control of noise pollution from stationary sources, including geothermal development activities, will likely continue to be at the discretion of state or local regulators, except for those operations on federal lands controlled by USGS noise regulations (GRO Order No. 4).